Subsurface Impacts of Hydraulic Fracturing: Contamination, Seismic Sensitivity, and Groundwater Use and Demand Management

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Executive Summary

A major concern with unconventional gas development relates to hydraulic fracturing and the associated risk of adverse subsurface impacts, including groundwater contamination, induced seismicity, and unsustainable groundwater use. As extraction of tightly-bound natural gas becomes more economically feasible due to improved technologies, unconventional gas development is likely to expand. However, many knowledge gaps exist regarding environmental impacts from hydraulic fracturing, and it is vital to groundwater resources and environmental protection that these are addressed and filled. This report reviews ten of the most important knowledge gaps around subsurface impacts from hydraulic fracturing, each in their own section of the report, in which the authors assess the current state of knowledge, identify the knowledge gaps themselves, and provide general research approaches to address these gaps.

Sections 1-3 pertain to stray gas and water quality issues. Section 1 focuses on baseline water quality and the natural methane system in the absence of hydraulic fracturing activities, which first must be understood in order to identify impacts from hydraulic fracturing. While many aspects of the methane system are well constrained, our understanding is not complete, especially regarding the intermediate zone and on time scales relevant to shale gas development. Furthermore, current monitoring strategies largely rely on domestic water wells, which are useful to understand *well water quality*, but offer insufficient information about *groundwater quality* and subsurface hydrogeochemical processes. Section 2 identifies challenges in understanding stray gas migration from production and intermediate zones. Leaking wells have been established to be an important source of stray gas, but there is little research on the role of natural fractures and faults in creating pathways for methane to reach shallow aquifers. Additionally, it is difficult to track and predict methane migration due to ebullition, degassing, and oxidation. In Section 3, several knowledge gaps are identified relating to water quality impacts from stray gas in shallow aquifers. Accumulation of free methane can result in an explosion hazard, while biogeochemical reactions that remove methane such as bacterial sulfate reduction can form H_2S and increase solubility of metals, affecting water quality from health-based and aesthetic concerns. However, there is a lack of high-quality scientific data in the peer-reviewed literature to understand the real risk to drinking water.

Section 4 examines mathematical models as a tool to understand water quality impacts from hydraulic fracturing. Advanced new models that include coupled geo-mechanical and multi-phase flow and reactive processes are needed together with reliable field data for model calibration and testing. Importantly, test sites need to be established where deep and shallow groundwater can be monitored to improve process understanding and to help detect the impacts of shale-gas extraction activities.

Section 5 addresses the risk of induced seismicity from hydraulic fracturing. Although there have been few occurrences of felt seismicity from hydraulic fracturing compared to other activities (e.g. waste water disposal), seismic events have been associated with shale gas activity in Canada and the U.S. The serious nature of potential consequences requires consideration of inherent hazards of fault-slip triggering during fracturing operations. Major challenges exist in understanding the relationship between various factors of hydraulic fracturing (e.g. injection volume, rate, reservoir pressure, etc.) and induced seismicity, as well as how to identify critically stressed faults.

Sections 6-8 consider groundwater quantity issues in relation to hydraulic fracturing. Findings within these sections reveal a lack of accessible and easily interpretable data regarding groundwater use for shale gas extraction activities. Section 6 examines how much groundwater is used in hydraulic fracturing, a question that is difficult to answer in part due to different permitting, regulating, and reporting standards in each province. In many cases, regulations were establishes several decades ago, before the rapid development of shale gas extraction. Gaps in information about groundwater use lead to incomplete understanding of the impact on the overall water budget, the subject of Section 7. Canada is a water-rich country, and thus effects are likely to be local. This section highlights the goal to avoid incidence, as Canada is in a position to prevent water scarcity issues. Section 8 investigates impacts of groundwater use for hydraulic fracture on other users in the water market. A lack of accessible data constitutes the largest challenge in addressing this knowledge gap.

Section 9 explores the challenges in understanding externalities related to subsurface impacts from hydraulic fracturing. For instance, perceptions of groundwater contamination can have significant economic impacts, such as changes in the housing market, even if those risks are not real. This section shows that to fully understand all external impacts of hydraulic fracturing, a full cost-benefit analysis is needed.

Section 10 reviews the knowledge gaps around the chemicals injected into the subsurface in the hydraulic fracturing process and deep well injection. The former subject is currently not considered to be a high priority, but was the topic that garnered significant public attention early in the hydraulic fracturing process. The principal knowledge gap around deep well injection are related to Section 5 (induced seismicity) insofar as induced fractures may provide pathways by which frack chemicals might migrate out of the target zone.

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Introduction and Report Organization

This report reviews the state of the knowledge around the subsurface impacts of hydraulic fracturing, including groundwater quality impacts, seismic sensitivity, and groundwater use and demand management. The existing scientific literature is reviewed, with two goals:

i) Evaluating the perceived knowledge gaps around subsurface and groundwater impacts (including groundwater supply issues)
ii) Identifying and describing the range of approaches that can be used to overcome the identified knowledge gaps.

The Canadian Water Network (CWN) funded this project (along with four sister projects on related topics) with the goal of subsequently seeking integrated research funds to address the identified knowledge gaps in order to assist decision-makers. Graduate students and post-doctoral associates have worked alongside faculty members at five Canadian universities to conduct the work presented here. This report is not concerned with surface activities and impacts of hydraulic fracturing (e.g. water impoundment at surface, trucking, air emissions, etc.) since these are the topic of one of the sister CWN reports.

Shale gas is differentiated from decades of hydraulic fracturing in that multiple wells are drilled from a single well pad, and long, horizontal well sections are hydraulically fractured. The details of this new approach have been described elsewhere (e.g. King, 2012; CCA, 2014) and are not repeated here. Clearly shale gas has proven to be an unanticipated resource, both economically and in geographical extent, that has provided a step function transformation of the energy sector in many countries, including Canada where more than 2,400 horizontal wells have been completed in B.C. alone (Stefik, pers. comm., 2015). Although this is a small fraction of the total number of vertical wells that have been hydraulically fractured in Western Canada since 1950 (~175,000; CAPP, 2012), the rapid rise in shale gas activity has caused substantial public concern in various parts of Canada and elsewhere (Jackson et al., 2013). Water use and water quality impacts are typically the most significant concerns articulated by the public (Al et al., 2012; Nova Scotia Independent Panel on Hydraulic Fracturing, 2014; Yukon Legislative Assembly, 2015).

Geographically, current shale gas development is mainly concentrated in Saskatchewan, Alberta, and British Columbia, where there is either a history of petroleum development and/or low population densities (Figure 1). This prospect of shale gas development has been met by public concern in many other parts of Canada, however, and is being evaluated in the Yukon and Northwest Territories, Quebec, New Brunswick, and Nova Scotia. While it is not clear whether public concern, sometimes referred to as a lack of a 'social license to operate' (Thomson and Boutilier, 2011), is because of a lack of historic experience with oil and gas development, higher rural residential population densities (which are often accompanied by increased reliance on groundwater for domestic water supply), or other reasons. Nonetheless, impediments to energy development make it clear that public opposition is strongly held in some regions. There are a number of locations in Canada and elsewhere where hydraulic fracturing has been slowed or under moratoria due to public concern (Table 1).

Figure 1. Map of unconventional plays in Canada (NRCan, 2013).

Table 1: Jurisdictions in which unconventional oil and gas development has been impeded due to lack of a 'social license to operate'.

Jurisdiction	Nature of impediment and steps to address it
Nova Scotia	Recent prohibition of high volume hydraulic fracturing, following an independent review of hydraulic fracturing emphasizing the precautionary approach (Wheeler et al., 2014).
New Brunswick	Recent moratorium on hydraulic fracturing, following strong opposition from First Nation and other community groups. Creation of New Brunswick Energy Institute (http://nbenergyinstitute.ca/) to "provide objective science-based information to help New Brunswickers evaluate the possible impacts from the potential development of energy resources and infrastructure."
Quebec	Hydraulic fracking moratorium currently in place due to public concern (Bott et al., 2013). Provincially funded research program and *Bureau d'audiences publiques sur l'environnement* (BAPE) to engage citizens.
Yukon	All oil and gas exploration and development prohibited in the Whitehorse Basin, although not under threat of exploration. Government is open to responsible shale gas development in the Laird Basin, but any shale gas development must have support of affected First Nations. (J. Miller (Hydrogeologist, Yukon Government), pers. comm., 2015; Government of Yukon, 2015)
New York	Permanent ban on high volume hydraulic fracturing (FracTracker Alliance, 2014)
Alleghany County, PA	Current ban on hydraulic fracturing in Pittsburg (in Allegheny Co), but the drilling allowed in certain other parts of the county, which has resulted in increased truck traffic and population growth in rural areas (Lampe and Stolz, 2015)
Mora County, New Mexico	Ban on extraction of oil, natural gas, or other hydrocarbons, as well as water for use in any oil and gas activities (Ritchie, 2014).
Germany	Nation-wide ban on hydraulic fracturing in specific regions to protect drinking water, health, and the environment (SHIP, 2015).
France	Federal government ban on hydraulic fracturing, largely due to public opposition – as much as 80% of the French population opposes hydraulic fracturing (Chu, 2014)

Abundant literature reviews and 'white papers' are now available on shale gas development and hydraulic fracturing (Table 2), and the increase in shale gas papers in the refereed scientific literature is impressive, in particular since 2008 (Figure 2).

The lack of a scientific consensus on subsurface impacts of hydraulic fracturing is clear. This is partly apparent by the almost unprecedented rate of 'back-and-forth' comments and author response on published papers. For example, one paper on well water methane in Pennsylvania (Osborn et al., 2011a) prompted three comments (Davies, 2011; Saba and Orzechowski, 2011; Schon, 2011), two corresponding replies (Osborn et al., 2011b; Jackson et al., 2011), and an additional paper (Molofsky et al., 2011) clearly directed at rebutting the initial conclusions within seven months. Refereed publications sometimes come to completely opposing conclusions – for example, Myers (2012) cites 'less than ten years of travel time' of water from the hydraulic fracturing interval to near-surface, while the U.K.'s Royal Society and Royal Academy of Engineering (2012) concluded that flow and transport from frack zones to shallow aquifers was not possible. Our scientific understanding is clearly not 'settled' and requires sound research. In our view, 'sound science' combines the consistent application of the

scientific method until convergent objectivity, when scientific 'agreement' is achieved (Douglas, 2009). Scientific consensus requires multiple, independent lines of evidence, uses 'discipline standards', and should be reproducible.

Table 2: White papers related to hydraulic fracturing and shale gas development (listed chronologically). National contributions from countries other than Canada, and provincial and regional contributions from within Canada are included.

Year	Title	Sponsoring Agency
2015	Final Report of the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing	Yukon Government
2014	Managing the Risks of Hydraulic Fracturing	Fraser Institute (Canada)
2014	Environmental impacts of shale gas extraction in Canada. The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction.	Council of Canadian Academies
2014	Report of The Nova Scotia Independent Panel on Hydraulic Fracturing	Nova Scotia Government
2013	Water and Hydraulic Fracturing: A White Paper	American Water Works Association
2012	Engineering Energy: Unconventional Gas Production: A Study of Shale gas in Australia.	Australian Council of Learned Academies
2012	Shale Gas Extraction in the U.K.: A Review of Hydraulic Fracturing.	Royal Society and Royal Academy of Engineering
2012	Hydrofracking Risk Assessment: Study Concerning the Safety and Environmental Compatibility of Hydrofracking for Natural Gas Production from Unconventional Reservoirs.	German Federal Government
2012	State of the Art: Fracking for Shale Gas Exploration in South Africa and the Impact on Water Resources	South Africa Water Research Commission
2012	White Paper Summarizing the Stray Gas Incidence and Response Forum	Groundwater Protection Council (US)
2012	Opinion: Potential Impact of Shale Gas Exploitation on Water Resources	University of New Brunswick
2012	Shale Gas in Canada. Background Document for the Pembina Institute Thought Leaders Forum. Towards Responsible Shale Gas Development in Canada	Pembina Institute
2011	Sustainable Development of the Shale Gas Industry in Québec Inquiry and Public Hearing Report	Québec Bureau d'audiences publiques sur l'environnement

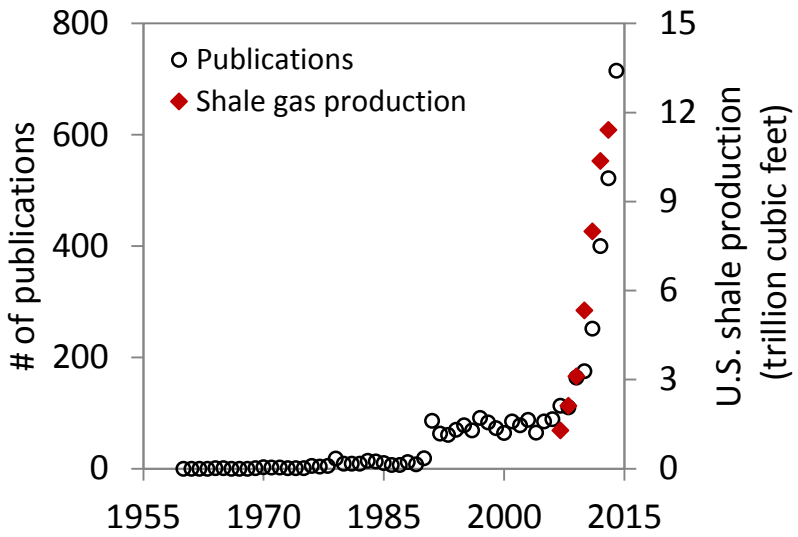

Figure 2. The number of publications retrieved from the 'Web of Science' index for each year when "shale gas" is entered as topic (data retrieved March, 2015) compared to shale gas development in the U.S. (data available since 2007).

The goal of this report is to: i) evaluate the perceived knowledge gaps around subsurface and groundwater impacts (including groundwater supply issues) and ii) identify and describe the advantages and disadvantages of various approaches to overcome the identified decision-making knowledge gaps. This report follows the Council of Canadian Academies' "Environmental Impacts of Shale Gas Extraction in Canada" paper, which was developed by an Expert Panel that included four team members from this report (Dr. John Cherry (Chair), Bernhard Mayer, John Molson, and Beth Parker). The Expert Panel completed their research on December 3, 2013, and the CCA report was edited prior to its release on May 1, 2014. This CWN report is a logical follow-on to the CCA report, insofar as the Council of Canadian Academies' reports do not specifically identify knowledge gaps or make recommendations *per se*, but rather provide an assessment of the 'state of the science', including knowledge gaps. This CWN report brings the 'state of the science' up-to-date (i.e. since the completion of the Council of Canadian Academies report in December, 2013), prior to identifying priority knowledge gaps and providing a range of approaches to address the identified knowledge gaps.

The range of possible approaches to address the knowledge gaps was developed by evaluating research that have been conducted within the current topic, and then evaluating approaches used to address topics of a similar nature. Each chapter includes a table that lists the range of approaches that could be used to address the gaps in the order of increasing complexity (and expense), with the pros and cons similarly included. The knowledge gaps are identified around several categories of risks, including subsurface pathways for methane migration (Sections 1-4), induced seismicity from hydraulic fracturing and/or deep well injection (Section 5, with some reference to Section 4), groundwater use (Sections 6 to 8), externalities associated with hydraulic fracturing (Section 9), and risks associated with the deep zone (including the fate of chemicals used in hydraulic fracturing and disposal by deep well injection; Section 10).

This report is organized around knowledge gaps identified by the team as priorities for decision- and policy-makers. The team limited themselves to ten knowledge gap sections – a number that was chosen to be comprehensive, but not overwhelming. Each of these knowledge gap groups are contained in a report section. They are listed in part in order of perceived importance (as assessed by the research team), with allowances for some thematic grouping. For example, while water quality impacts of stray methane migration (Knowledge Gap 3) are believed to be one of the most important issues, sections on baseline water quality and methane migration pathways (Knowledge Gaps 1 and 2, respectively) are placed first to provide the appropriate background to water quality impacts of stray methane migration. Each section has an introduction, an up-to-date review of relevant literature including a summary of white paper reports (and in particular the 2014 CCA report), followed by a discussion of the knowledge gaps and range of research approaches (presented in table form) that could be used to address them. Sections are structured to read as self-contained chapters for direct accessibility to issue(s) of interest of decision-makers. This results in some overlap between sections.

In many cases the knowledge gaps are distinguished as "information gaps" and "understanding gaps". The former include data that are either already collated, or reasonably easy to collate, but not available to researchers seeking to address knowledge gaps. The lack of availability of information can be a roadblock to assessing knowledge gaps. Conversely, "understanding gaps" are knowledge gaps that require scientific inquiry to solve.

The investigators on this project recognize that decision- and policy-makers cannot anticipate easily obtainable and 'logically indisputable' answers to the gaps in understanding. Rather, the scientific process that accompanies our understanding of broad environmental issues is likely to be a continuous inquiry-based process, accompanied by 'scrutiny, re-examination, and revision', leading to a 'robust consensus' (Oreskes, 2004).

In order to address the knowledge gaps presented in this report, each chapter contains a range of research approaches aimed at improving current understanding. The research approaches are presented in table format, which include information about complexity, risk/uncertainty, timeframe, cost, research capacity, social/political concerns, implementation difficulty, and likely achievements. Most components are categorized as low/moderate/high, and are defined below:

- **Complexity:** A project of low complexity may be conducted by scientist trained at the B.Sc. level, and may use existing data and available techniques and/or equipment; a high complexity project requires research teams specializing in field of interest and development of new techniques and equipment.
- **Risk/Uncertainty:** Low risk approaches have clearly defined outcomes that are likely to be achieved because they use standard methods/techniques. High risk approaches are those with less likely outcomes, typically involving cutting edge research in highly uncertain research areas.
- **Timeframe:** Short timeframes can be accomplished within months, whereas long timeframes will require years
- **Cost:** Low cost projects are nominally up to 100K; high cost projects are greater >750K.
- **Research Capacity:** Low research capacity projects could be conducted by B.Sc. level scientists with supervision by more experienced team members, while high research capacity will involve specialists, likely in more than one field, working together on novel problems.

- **Social/political concerns**: Description of issues such as public sharing of data, public interest, controversy, etc.
- **Difficulty of Implementation:** In general, highly complex research projects will be difficult. Exceptions may be when information gaps are present , i.e. data exist, but are not available to researchers
- **Likely Achievements**: Description of expected outcomes, areas with improved understanding.

Finally, the increased interest in shale gas has been accompanied by new jargon. We clarify some of these terms here.

In this report hydraulic fracturing will be taken to mean the process of the well stimulation itself, and also all of the activities directly associated with the purpose of unconventional oil and gas development (e.g. from the initiation of drilling, through well construction, the hydraulic fracturing process, production and post-production stages).

Relative subsurface depths are often referred to as shallow, intermediate, or deep. The three subsurface 'zones' have somewhat subjective (but still functional) definitions as follows: i) the 'shallow zone' is the depth to which groundwater wells are, or might reasonably be, installed. In some jurisdictions, this is called the 'base of groundwater protection', and is defined as the base of the deepest non-saline groundwater-bearing formation plus a 15 m buffer (AER, 2013); ii) the 'deep zone' is the 'target' zone for hydraulic fracturing and petroleum product recovery. This zone is variable, but can be shallower than 1000 m, and as deep as 5000 m (Fisher and Warpinski, 2012); iii) the 'intermediate zone' includes the depths between the shallow and deep zones.

Finally, we consider stray gas to be gas in a geologic formation outside the wellbore that was unintentionally mobilized by hydraulic fracturing-related activities (Vidic et al., 2013). This gas could be in either the dissolved or free-gas phase.

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SECTION 1: What is the Prevalence, Origin, and Variability of Methane in the Shallow and Intermediate Zone Before Hydraulic Fracturing? How Can Baseline Groundwater Quality Most Effectively be Assessed?

1.1 Introduction

Before scientists and policy makers can accurately assess the impacts of hydraulic fracturing on the subsurface in a meaningful way, the natural methane system must first be fully characterized and understood, including natural baseline conditions from which impacts of fracking can be delineated. Only when methane origin, and its natural occurrence, distribution, and temporal and spatial variability are understood for all relevant settings can the impact of hydraulic fracturing on these systems be determined. The challenge is to conduct monitoring that will identify changes in methane distribution due to shale gas development.

For the purpose of this report, the term baseline refers to the natural conditions (both hydrogeological and hydrogeochemical) at any location or within any component of the natural system that is related to and may be affected by hydraulic fracturing. It is the ambient conditions from which significant deviation would indicate that hydraulic fracturing has had an impact. This encompasses both regional scales in areas of shale gas development and local scales around specific hydraulic fracturing pads and/or nearby domestic wells. Baseline condition refers to all depth scales (i.e. shallow, intermediate and deep) and its determination is the basis of assessing any impacts for any purpose (e.g. liability, forensic identification, presence of impacts on domestic wells, etc.).

This section first reviews the existing literature and state of knowledge regarding natural prevalence, origin and variability of methane in the subsurface and determination of baseline conditions. Key literature is described in detail, including limits of current understanding. The literature review explores the various facets of natural methane presence, first examining origins and distribution, and then outlining key issues related to shale gas development, i.e. methods used for forensic identification of stray gas. Following the literature review, knowledge gaps associated with these issues are identified and described before potential research approaches with which to address these gaps are identified and assessed.

1.2 Literature Review

The natural presence and abundance of methane in different regions is an issue that has received varying levels of interest over the past 50 years. Interests and applications that have driven this attention have included concern for explosion hazard from methane-rich well water, hydrocarbon prospecting, delineating landfill leachate plumes, determining natural attenuation properties, and curiosity about methane origin and genesis. As such, the genesis and degradation of methane in a groundwater context is reasonably well understood, and many scientific papers exist with varying relevance to shale gas studies. Only the most relevant papers inform this review.

1.2.1 Methane Origin in Groundwater

Methane in shallow groundwater systems is typically biogenic, while deeper methane is thermogenic, and either or a mixture of these sources exist in the intermediate zone. Thermogenic methane occurs where thermal

'cracking' of sedimentary organic matter produces methane and other short chain hydrocarbons. Biogenic methane, on the other hand, is generated by bacteria during metabolism of organic matter under low pressure and temperature conditions (Schoell, 1988), and is produced as the final reaction in a thermodynamically predicted sequence of redox reactions for originally oxygenated groundwater evolving in a closed system. Thus, biogenic methane is commonly observed in SO_4-depleted waters (Claypool and Kaplan, 1974), as production occurs after sulphate reduction and at very low Eh (i.e. less than -200 mV; Stumm and Morgan, 1970). The two primary mechanisms for biogenic formation are acetate fermentation and CO_2 reduction – processes that can occur in parallel or independently – with the latter generally believed to be the dominant mechanism in aquifer systems (Barker and Fritz, 1981; Schoell, 1988).

$CH_3COOH \rightarrow CH_4 + CO_2$ (Acetate Fermentation)
$CO_2 + 4\ H_2 \rightarrow CH_4 + 2H_2O$ (Carbon Dioxide Reduction)

The parent organic matter necessary for methane genesis can be present in both shallow, unconsolidated deposits and deeper, bedrock strata (including organic rich shales; Kaczynski and Kieber, 1994). Dissolved organic carbon concentrations as low as 0.1 mg/l can be sufficient to allow methanogenesis to take place (Darling and Gooddy, 2006), thus the potential for methanogenesis is ubiquitous as most unconsolidated geologic formations and various types of rock matrix can easily supply such levels.

In general, the most reactive forms of organic matter (usually relatively young organic matter derived from soils; Whitelaw and Edwards, 1980) will initially be used in methanogenesis (Darling and Gooddy, 2006). Shallow groundwater systems with dynamic flow regimes will flush generated methane relatively rapidly, preventing build-up to any significant concentrations. In deeper systems, relatively slow groundwater flow regimes and long residence times may allow for increased methane concentration with time. If methane concentrations increased to the point that total dissolved gas pressure exceeds the bubbling pressure (approximated as the sum of hydrostatic and atmospheric pressures), methane may partition into the free gas form (Roy and Ryan, 2013).

Since surface-sourced reactive organic matter does not usually migrate to significant depths (based on its reactive nature and long timescales/residence times required for such deep migration), sedimentary organic carbon tends to be the main source for deep methanogenesis. Even if present in significant amounts, organic matter at depth is more likely to be in stable, or recalcitrant, forms which are not bioavailable. Thus, shallow aquifers under appropriate redox conditions can potentially form methane at a significant rate, while deeper aquifers may only do so over longer time scales. Groundwater residence times can control whether there is significant accumulation. This infers that groundwater systems that may have previously generated and contained methane may no longer have detectable levels. Various studies have arrived at some degree of converging objectivity concerning these phenomena, as discussed below.

1.2.2 Methane Distribution in Groundwater

The distribution of methane in groundwater systems is controlled by presence, abundance, and type of organic matter as well as variations in redox conditions (Darling and Gooddy, 2006). For example, phenomena such as anaerobic micro sites (Murphy et al., 1992) or organic matter from the soil zone coating bedrock strata fracture surfaces has been observed to influence distribution (Lawrence and Foster, 1986).

Typically, more biogenic methane exists in the shallow zone, as shown by an early study involving groundwater sampling from ten regions in North America in order to determine the natural occurrence and origin of methane in shallow groundwater flow systems (Barker and Fritz, 1981). This work relied on the distinct isotopic signatures of biogenic and thermogenic methane (Figure 1.1; Schoell, 1980), as well as hydrogeological and hydrogeochemical characterization. Biogenic methane was found to be common and ubiquitous in shallower flow systems, while thermogenic methane was much less prevalent. Isotopic analysis clearly distinguished between the two gas origins, as well as anthropogenically generated methane.

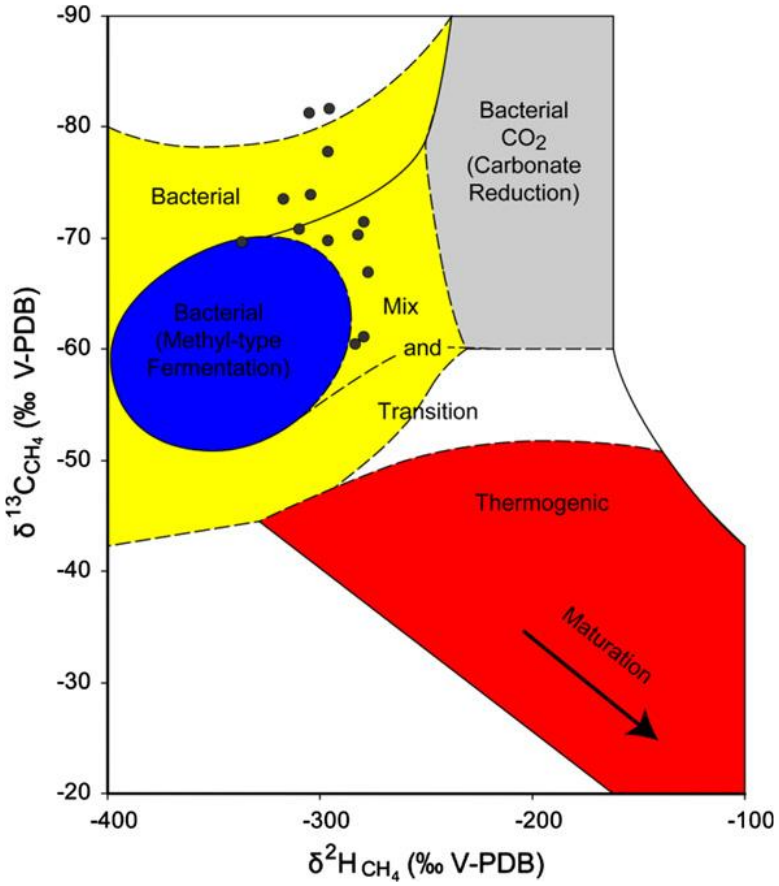

Figure 1.1. ^{13}C and deuterium values in naturally occurring methane clearly show origins/mechanisms of gas formation (Cheung et al., 1999, adapted from Whiticar, 1999).

Such work paved the way for more detailed and wide-ranging studies over the next three decades, exploring many aspects of methane in groundwater systems exploited for anthropogenic use. For example, Hansen et al. (2001) studied an anoxic, pristine, phreatic unconsolidated glacial sand aquifer on the island of Rømø in Western Denmark in order to elucidate processes involved with methane genesis and presence. Water samples collected to eight meters depth using precision pneumatic drill sample points at three locations were analysed for a comprehensive geochemical data set. Key observations and conclusions include: i) spatial distribution of methane was not consistent with probable locations of significant methanogenesis, ii) methane was produced in one part of a shallow system and migrated to an area with little or no methanogenesis, iii) the rate of methanogenesis was controlled by the rate of degradation of organic matter into simpler constituents (i.e.

substrates for methanogenesis), iv) redox zonation and the concept of competitive exclusion (e.g. Jakobsen and Postma, 1999) controlled the distribution of methane, and v) the presence or absence of H_2 was not a reliable indicator for the predominant electron accepting process occurring.

Another study found that redox conditions alone do not exert ultimate control on presence and distribution of methane in groundwater systems (Kaczynski and Kieber, 1994). Darling and Gooddy (2006) evaluated water samples across major aquifers in England, taking samples from municipal, industrial, or domestic wells exploiting the southern Chalk, Lower Greensand, Lincolnshire Limestone, and Sherwood Sandstone. They observed detectable levels of methane almost ubiquitously throughout all systems studied, which included the full spectrum of redox states. These results indicate that redox conditions are not the sole influence on presence and distribution of methane in the subsurface, and even water equilibrated with atmospheric concentrations can provide detectable levels of methane in pristine groundwater (i.e. > 0.05 µg/l). The authors found that lateral migration or strata contacts likely affect the subsurface distribution of methane, and observed no evidence of thermogenic methane leakage from depth to shallower strata. Overall, the study concluded that methane in aquifers in England is likely generated at two rates: i) rapid production from labile (easily broken down) carbon in shallower aquifers or microsites within deeper strata, and ii) millennium-scale production from more recalcitrant carbon sources in deeper freshwater aquifers.

In order to understand the influence of bedrock lithology on methane distribution, Aravena et al. (1995) examined the presence and origins of methane in the Alliston aquifer in southern Ontario, a confined system comprised of sand and gravel lenses that is underlain by Paleozoic bedrock and overlain by glacial till. Using geochemical and isotopic data collected from domestic and commercial water supply wells at various depths and locations, the authors concluded that bedrock lithology had no spatial correlation with methane presence, and the methane gas was of biogenic origins formed by CO_2 reduction sourced from the organic rich aquifer matrix itself.

In contrast, a more recent study found bedrock geology to be a key control of methane occurrence in natural systems (McIntosh et al., 2014). Analysis of water samples collected from > 1000 domestic water wells completed in both bedrock and overburden aquifers in southwestern Ontario showed that dissolved methane comprised the majority of total gas composition. The highest methane fractions were found in bedrock wells completed in several key organic rich strata or surficial aquifers overlying them (Figure 1.2). Results were interpreted to indicate that methane presence was correlated with bedrock in natural systems. While this differs with the conclusions of the above study conducted in the Alliston aquifer (Murphy et al., 1992), the two studies were consistent in their conclusions that the vast majority of well water methane was biogenic in origin, with occurrence apparently controlled by the presence or absence of organic substrates and electron acceptors (DO, Fe, NO_3, SO_4, etc).

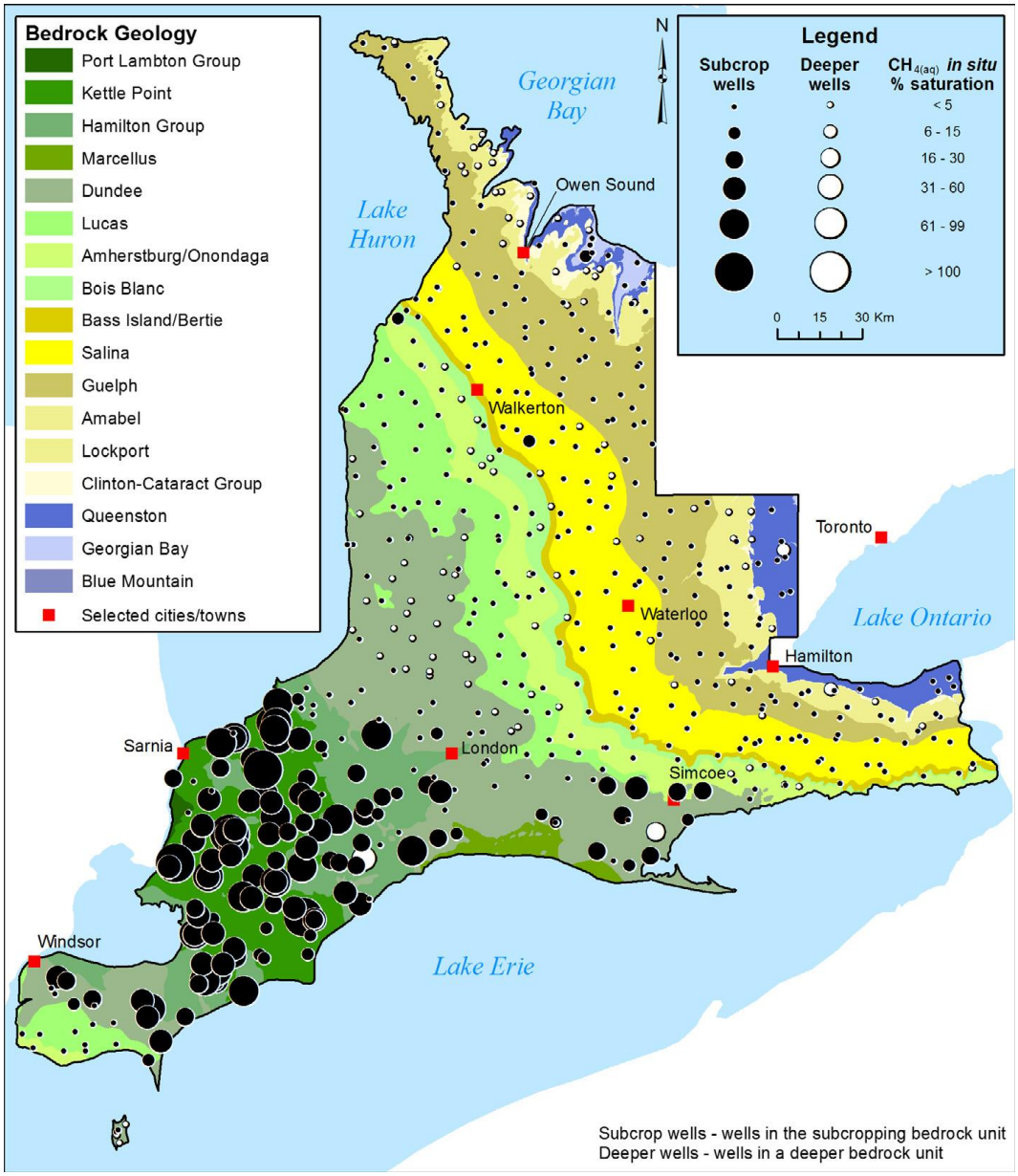

Figure 1.2. Bedrock geology map of southwestern Ontario with dissolved methane (CH4) content (in-situ % saturation) in water supply wells (McIntosh et al., 2014). Samples containing >100% in situ CH4 saturation may result from bubble entrainment during sampling.

1.2.3 Distinguishing Natural Methane from Suspected Stray Gas Contamination

The vast majority of recent research is related to identifying impacts at areas with suspected or known stray gas presence and determining origins of the stray gas. So far, the general procedure involves determining the presence of elevated methane concentrations in areas of shale gas development and then identifying sources/causes (Rowe and Muehlenbachs, 1999; Osborn et al., 2011a). The latter is primarily performed using the stable isotope composition of methane from domestic well samples to determine biogenic or thermogenic origins (Sakata et al., 1997; Osborn and McIntosh, 2010; Revesz et al., 2012). However, major debate exists about correlation (of methane presence and abundance with factors related to hydraulic fracturing) and

causation (i.e. hydraulic fracturing solely responsible for observed methane presence and abundance or changes in methane concentration), and remains a point of contention between research teams. Perhaps the most controversial example is that of the intense scientific argument that followed Osborn et al.'s (2011a) publication showing the average methane concentration in groundwater from wells within one km of shale gas production were three times higher than that of wells farther away (Figure 1.3). The authors sampled 68 domestic wells in North Eastern Pennsylvania to search for evidence of shale gas impacts, and attributed the results to the drilling of the wells and gas extraction. The conclusions of this paper were rapidly refuted as inconclusive (Davies, 2011; Saba and Orzechowski, 2011; Shon, 2011) to which further debate ensued (Jackson et al., 2011; Osborn et al., 2011b). A further paper was released two years later in which an increased data set (141 wells across the Appalachian region) was evaluated for a more extensive set of analyses to determine potential impacts from shale gas development by hydraulic fracturing (Jackson et al., 2013). Again, results showed elevated levels (by up to six times) of methane and ethane in wells less than one km from a shale development pad, from which the authors inferred correlation. In contrast, a study by Molofsky et al. (2013) of 1,701 different water wells in almost the same area concluded that methane concentrations best correlate to topographic and hydrogeologic features, rather than shale gas extraction (Figure 1.4). Clearly, there is little consensus in the research community on this issue. Unfortunately, the science behind these studies is not reproducible, as the domestic well owners and locations are not identified due to legal reasons. Thus, without further sampling and testing of data, consensus is unlikely to be reached.

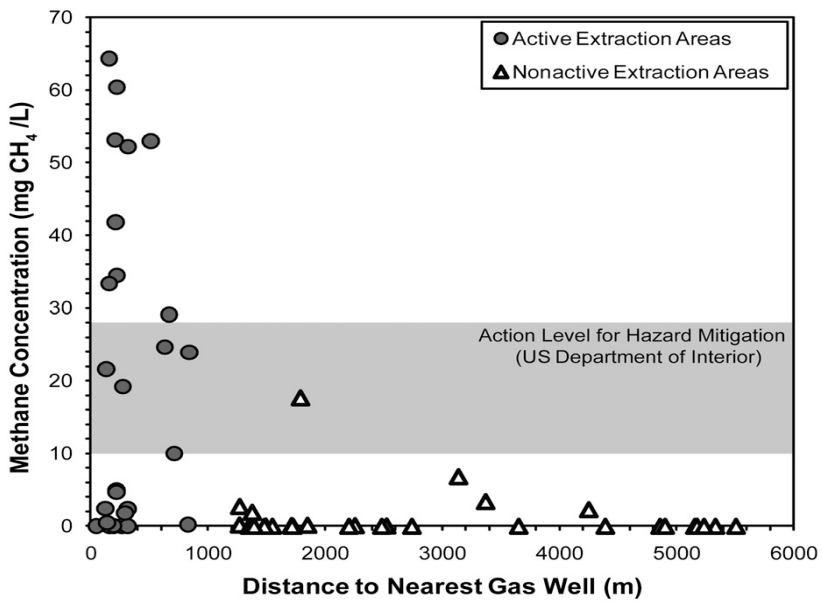

Figure 1.3. Methane concentrations (milligrams of CH4 L−1) as a function of distance to the nearest gas well from active (closed circles) and nonactive (open triangles) drilling areas (Osborn et al., 2011a). Note that the distance estimate is an upper limit and does not take into account the direction or extent of horizontal drilling underground, which would decrease the estimated distances to some extraction activities.

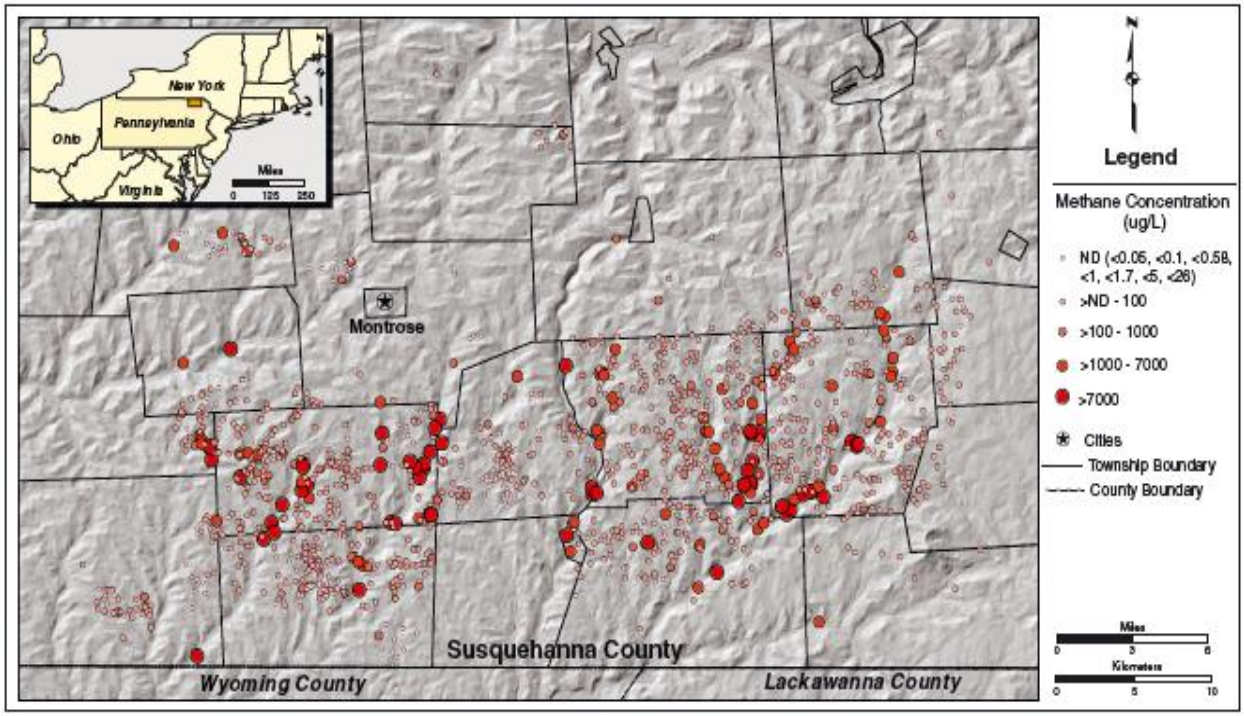

Figure 1.4. LiDAR bare-earth elevation map showing dissolved methane concentrations from 1701 "predrill" water wells sampled in Susquehanna County (Molofsky et al., 2013).

Aside from well blowouts and a few cases of inter-borehole communication (ERCB, 2012; Dusseault and Jackson, 2014), no confirmed case of hydraulic fracturing derived subsurface impacts have currently been reported by the industry in the literature, likely related to the politically charged and controversial nature of the topic. However, several confirmed historical cases of conventional/unconventional gas development derived contamination may offer some insight into likely impacts.

One such historical case study occurred near Lloydminster, Alberta (CAPP, 1995). Lloydminster is situated near the border between Alberta and Saskatchewan in a rural region where the dominant land uses are agriculture and oil and gas production. Methane migration into the shallower subsurface from various oil and gas development activities was identified in the 1980s. The methane gas appeared to have leaked along the annuli of the production wells at depth, as seen in other cases (e.g. Harrison, 1983; Chafin, 1994), before dispersing readily throughout the shallower strata through networks of fractures and other pores spaces. Various studies examined the contamination, initially identifying the leakage, and subsequently exploring different aspects of the chemical system as the contamination matured. For example, a study published in 2005 explored processes associated with anaerobic bacterial sulphate reduction of stray methane (Van Stempvoort et al., 2005). Results showed that this attenuation process had been occurring, but only in groundwater containing sufficiently high sulphate concentrations. Where little or no aqueous sulphate was present, stray methane was recalcitrant and was not oxidized.

Another confirmed case of methane contamination involved a well blow-out during drilling, an example of an acute hydraulic fracturing derived fugitive methane event (Kelly et al., 1985). The event occurred near North

Madison, Ohio in 1982 when unconventional gas well drilling penetrated a natural gas pocket. Penetration allowed the natural gas to travel up an uncased wellbore and invade the overlying formations (presumably via pre-existing fractures). The result was gas-charged mud boils at several locations, furious methane bubbling in water wells and surface waters, and uplift of nearby shale beds. The event damaged several properties and precipitated a small explosion, but caused no fatalities. A follow-up study examined two water sample sets 74 and 265 days after the blow-out from eight water wells located approximately 0.7 – 1 mile from the culprit gas well (Kelly et al., 1985). Elevated concentrations of $Fe^{2/3+}$, Mn^{2+}, Ca^{2+}, HCO_3, S_2, elevated pH values, and decreased O_2, SO_4 and NO_3 concentrations implicated methane oxidation as the main driver of chemistry change associated with CH_4 contamination. In addition, the authors performed a simple laboratory batch study with formation groundwater (without any sediment) to assess effects of gas phase CH_4 on water chemistry. Batch results support bacteria-mediated sulphate reduction as the key driver of geochemical changes. Although an elegant and useful study, and one of the first in situ investigations on shallow aquifer CH_4 contamination, this work is limited by the low number of water quality analyses from which to draw conclusions, no real background samples, limited hydrochemical results, and no information on the associated sedimentology/mineralogy and its role on water chemistry change.

Significant methane gas migration also occurred in a recently hydraulically fractured vertical energy well in Bainbridge, Ohio (Bair et al., 2010). On December 15th 2007, an explosion occurred, damaging a house and causing the evacuation of 19 properties. Subsequent investigation determined that a total of 49 properties had been affected by methane migration in the free gas phase, with significant impacts to private wells and water supplies. The gas source was determined to be a recently drilled and hydraulically fractured energy well. The methane originated from a non-target formation located directly above the target formation. Gas migration occurred due to a combination of inadequate cement sealing of the production well casing (located below the surface casing) in a fault zone of a non-target formation, and the 'shutting in' of the well, which allowed annular gas pressures to rise, causing migration outside the surface casing and into the groundwater zone. Information on geochemical impact is unclear due to lack of background data.

1.3 Knowledge Gaps

The above studies elucidate several aspects related to the baseline characterization of aquifer systems and the natural occurrence and origins of subsurface methane, but it is clear our understanding is incomplete. Several key gaps in information and understanding exist and are summarized here.

1.3.1 Natural Occurrence, Abundance and Origins of Subsurface Methane Over Appropriate Temporal and Spatial Scales

Research associated with methane origins and occurrence to date has focused on the upper part of the 'shallow, freshwater zone' of the hydrogeologic profile (Figure 1.5, typically the zone where domestic water wells are screened, extending approximately 100 or 200 m depth, depending on the region and geologic setting). The next logical step is to expand this in terms of depth, scale, resolution, and accuracy. Based on current research, it is still unclear how methane is distributed throughout the deeper freshwater zone into and through the intermediate zone (Figure 1.5). Furthermore, spatial and temporal variation of methane concentrations and the frequency of free gas phase are poorly understood.

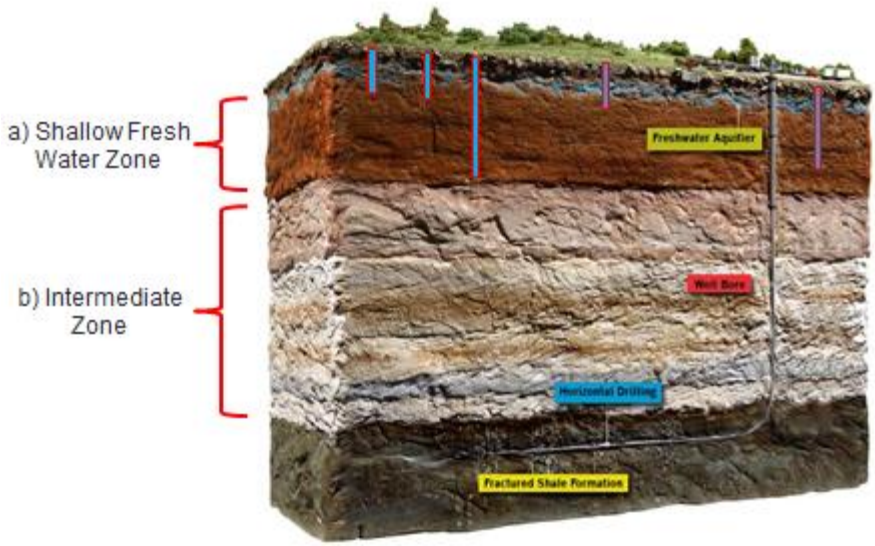

Figure 1.5. Conceptual division of groundwater zones. The shallow, fresh water zone is typically the depth to which water wells are screened, while the intermediate zone includes the depths between the shallow and shale gas target zones.

1.3.2 Appropriate Sampling Techniques

Crucially linked to the above knowledge gap is the ubiquitous use of domestic wells to investigate subsurface effects from hydraulic fracturing. While sampling domestic wells provides a measure of impacts at the point of consumption, and thus is useful from a human health risk standpoint, the use of domestic wells is fraught with limitations and drawbacks. Information on well construction (e.g. screen length and geologic unit being exploited), quality of well, hydraulic integrity, relative degree of water level drawdown during sampling, loss of free gas in sampling, and presence of bacterial contamination, for example, are not available for wells used in these studies. Additionally, as previously mentioned, scientific reproducibility is an issue as the locations of domestic wells are often not divulged. For these reasons, it is difficult to have full confidence in results and to make clear and consistent conclusions. Furthermore, scientific and statistical studies that use domestic well samples are difficult or impossible to reproduce, and significant variations in type and quality of installation can make some data questionable.

In order to address this knowledge gap, modern groundwater monitoring tools (i.e. high resolution multi-level monitoring systems) need to be employed in studies in various settings of interest. Ideally, both domestic sampling and high resolution, multi-level sampling systems should be employed to assess natural prevalence, origin, and abundance of methane in groundwater systems. Furthermore, measurements from both systems should be taken in parallel and compared in order to understand what they represent. Figure 1.6 compares the two types of sampling systems.

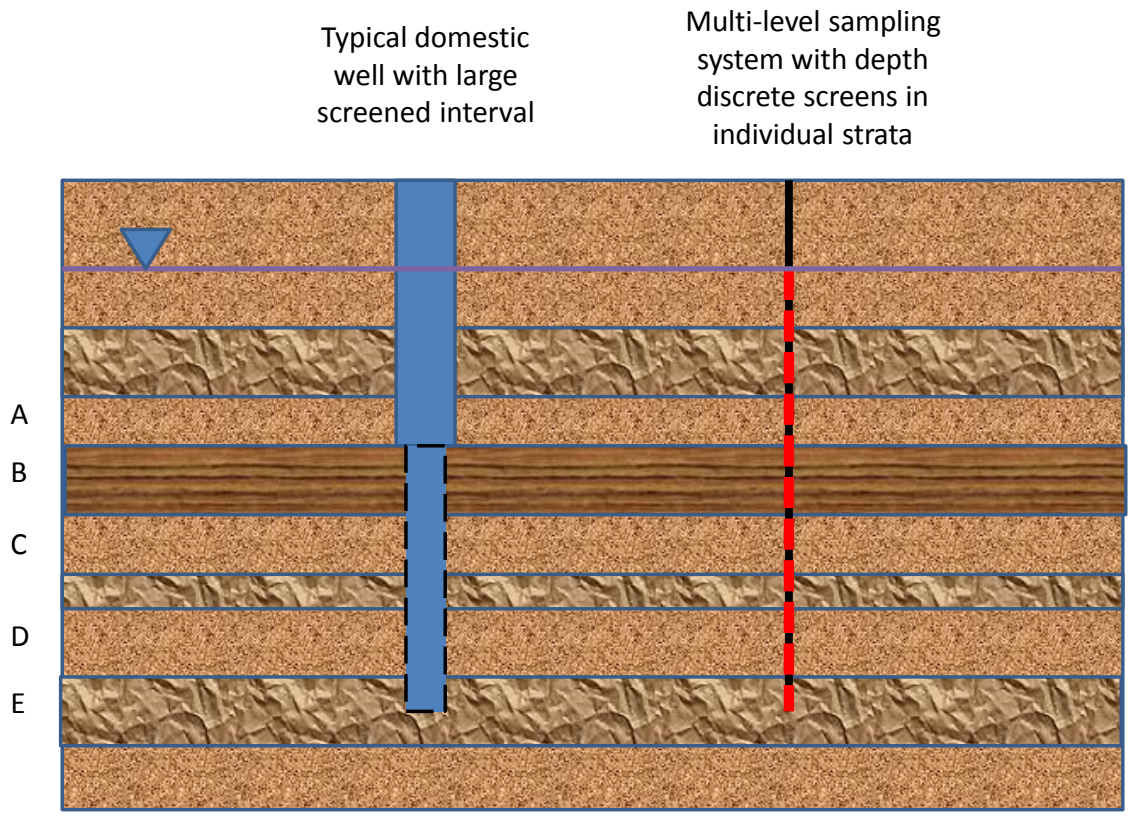

Figure 1.6. Comparison of sampling systems: domestic well versus depth discrete multi-level sampling system (MLS). Figure shows typical geologic profile which includes geochemically and hydraulically distinct strata (A – E). Use of the domestic well only would lead to mixed aqueous chemistry and lack of resolution making it difficult to reach firm conclusions. In order to accurately understand and characterize any natural system and potential impacts from shale gas development a depth discrete sampling system should be employed. Currently no depth discrete multi-level systems have been employed in any area of shale gas development.

1.3.3 Need for a Standard of Practice for Dissolved Gas Sampling and Analysis

Sampling dissolved gases is a difficult procedure, but an essential one for understanding the natural methane system in groundwater. The scientific community's acknowledgement of this is reflected in the exponential increase of dissolved gas studies since shale gas-related investigations have begun. However, as of yet there is no commonly accepted standard of practice for procedures related to groundwater or well water gas sampling, storage and transport, and analysis. This is particularly disconcerting given clear evidence that mass-loss of dissolved gases occur, such as bubbling during sampling (e.g. Lawrence and Foster, 1986; McIntosh et al., 2014). Since deeper water can hold more dissolved gas due to greater hydrostatic pressure, water samples that are pumped to the surface will degas (bubble) as the hydrostatic pressure decreases (Bair et al., 2010; Roy and Ryan, 2013). A variety of approaches have been taken to overcome the mass loss by ebullition including: i) sampling under a water column at surface to maintain gas pressure (Solomon et al., 2010), ii) using a copper tube sampler combined with vacuum extraction so that all gas mass is analysed, regardless of whether it is sampled in the dissolved or gas phase (Plummer and Busenberg, 2000), iii) estimation of total dissolved gas pressure in combination with gas composition analysis (McLeish et al., 2007), and iv) estimates of what the in situ gas solubility would be based on the water pressure associated with the screen depth (Lawrence and Foster, 1986).

Various reviews exist that have surveyed approaches for dissolved gas sampling and analysis (e.g. Barker and Dickout, 1988; ITRC, 2006; Hirsch and Mayer, 2009) but there are few studies designed to compare and contrast the available approaches (Labasque et al., 2014). Inherent in the lack of a standardized approach is the lack of understanding of mass loss by ebullition, and hence a poor understanding of the accuracy of the resulting dissolved gas concentrations.

1.4 Current Monitoring Approaches

The research approaches associated with understanding natural methane presence, occurrence, and origins currently employed and reported in the literature include the following:

- Sampling domestic wells over a (usually large) region of interest in order to characterize natural presence and origins of methane geochemically. This includes both the use of historical samples from databases and samples taken for this purpose.
- Specific sampling of the shallow subsurface (using dedicated sampling systems) over relatively small scales to understand the origins and genesis of methane and transport processes, often with insufficient spatial and temporal geochemical data.

Additionally, several jurisdictions in Northern America have mandated baseline groundwater sampling and analyses for landowner groundwater wells in predetermined distances from newly drilled oil and gas wells (e.g. AER Directive 35 in Alberta, COGCC Rules 609 and 318.e.(4) in Colorado, and Pennsylvania DEP). In many of these regulations it is recommended that baseline groundwater analyses determine the following:

- Concentrations of methane and higher n-alkanes for free or dissolved gas samples usually once prior to commencement of drilling the energy well;
- Isotope ratios of methane and higher n-alkanes for free or dissolved gas samples in groundwater usually once prior to commencement of drilling the energy well
- Parameters useful for identifying the redox state of shallow groundwater samples such as bacteriological analyses or trace element analyses (Fe, Mn etc.).

It is important to note that all jurisdictions rely on groundwater sampling using landowner wells rather than requesting the establishment of dedicated groundwater monitoring wells (although it should be noted some regions are making an effort to improve upon this; for example, Alberta recently expanded its Groundwater Observation Well Network, installing 13 new monitoring wells in emerging unconventional oil and gas plays). Also, baseline water quality sampling is usually only requested once per groundwater well, with follow-up testing requirement after drilling of the energy well varying widely in different jurisdictions (e.g. in Alberta only required after landowner complaints; in Colorado after 1, 3 and 6 years).

1.5 Range of Research Approaches

Table 1.1. Range of practical research approaches to address knowledge gaps.

	Research Approach 1: Use domestic wells in areas with varying levels of shale gas development (from zero to significant) to characterize CH_4 occurrence. Use of full geochemical suite of parameters including inorganics and isotopes. Note that provincial groundwater monitoring networks can also be included, although they are typically sparse.	**Research Approach 2:** Use cutting edge and highly discrete groundwater monitoring systems (e.g. MLS's and other new methods) in conjunction with traditional monitoring wells and or domestic wells over relevant temporal and spatial scales. Compare and understand differences in results from different sampling systems. Use of full geochemical suite of parameters including inorganics and isotopes.	**Research Approach 3:** Undertake controlled, small scale field and laboratory studies to further characterize CH_4 origins, prevalence, occurrence and fate. Use of full geochemical suite of parameters including inorganics and isotopes.
Complexity	Low; permission to sample domestic wells is only requirement.	Moderate to high; Employing new methods to understand natural methane distribution and variation requires development and testing. Becomes more complex at depth and larger scales.	Low/moderate; simple tests could easily be performed with complexity increasing
Risk/Uncertainty	High; currently this is only method employed and is highly controversial and uncertain. Domestic wells are not accurate groundwater monitoring tools.	Moderate; methods not previously employed in a shale gas development context; however are proven in other fields of geoscience i.e. contaminant hydrogeology	Moderate; upscaling of lab tests always uncertain (as for small scale field tests) since field-scale heterogeneity is not represented
Timeframe	Moderate to long term; 1 – 5+ years, the longer before and after development the better	Long term; 2 - 10 years, costs are significant and deployment of monitoring systems would only be justified for long term studies which would also gain greater insight	Short to moderate; some lab tests could be relatively short but longer tests more informative
Cost	Moderate to high; from high $100K's to low millions	High; $2 - 10+ million	Low to moderate; typically inexpensive but increased complexity and parameters can spiral costs
Research Capacity	High; expertise exists in federal government and academia however	High; expertise exists in federal government and academia particularly	High; expertise exists in federal government and academia

	usefulness of results is questionable	related to similar issues in science (i.e. wetlands or landfill)	particularly related to similar issues in science (i.e. wetlands or landfill)
Difficulty of Implementation	Low to moderate; access to wells and non-disclosure can be an issue.	High; highly complex and large scale projects required with many staff and significant 3rd party collaborations. Complex and difficult to manage	Low to Moderate; lab and small scale field studies can be relatively easy to conduct however increasing complexity can change this
Socio-Political Concerns	Low; the public would approve of this but likely do not understand the usefulness	Low; the public would approve of this but likely do not understand the usefulness	Moderate; public may view this action as 'too little' in terms of environmental protection
Likely Achievements	At best, moderately useful data which shows characterizes natural methane presence and occurrence, however blunt tools used will be associated with significant uncertainty	More comprehensive understanding of CH_4 prevalence, variability and origins in a natural system would be gained	Controlled studies may aid understanding of natural systems and provide more foundations in fundamental understanding of the natural methane system in the subsurface.

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SECTION 2: What Are the Important Subsurface Pathways and Mechanisms of Methane Migration?

2.1 Introduction

Fugitive gas associated with hydraulic fracturing can alter the natural occurrence and variability of methane. This disequilibrium can consequently affect subsurface geochemistry (Kelly et al., 1985; Vidic et al., 2013; Reddy et al., 2014). Identifying the subsurface pathways and mechanisms of fugitive methane remains a critical task.

Improperly sealed well casings, abandoned wells, permeable faults, or natural fractures can allow natural gas to migrate upward from unconventional gas plays or overlying formations (Figure 2.1; CCA, 2014). This migration can occur in the free or dissolved gas phase, and the mechanism of transport varies depending on the subsurface environment (e.g. saturated vs. unsaturated, confined vs. unconfined aquifer). This chapter will examine subsurface pathways resulting from leaking wells, the role of natural faults and fractures, and methane transport mechanisms.

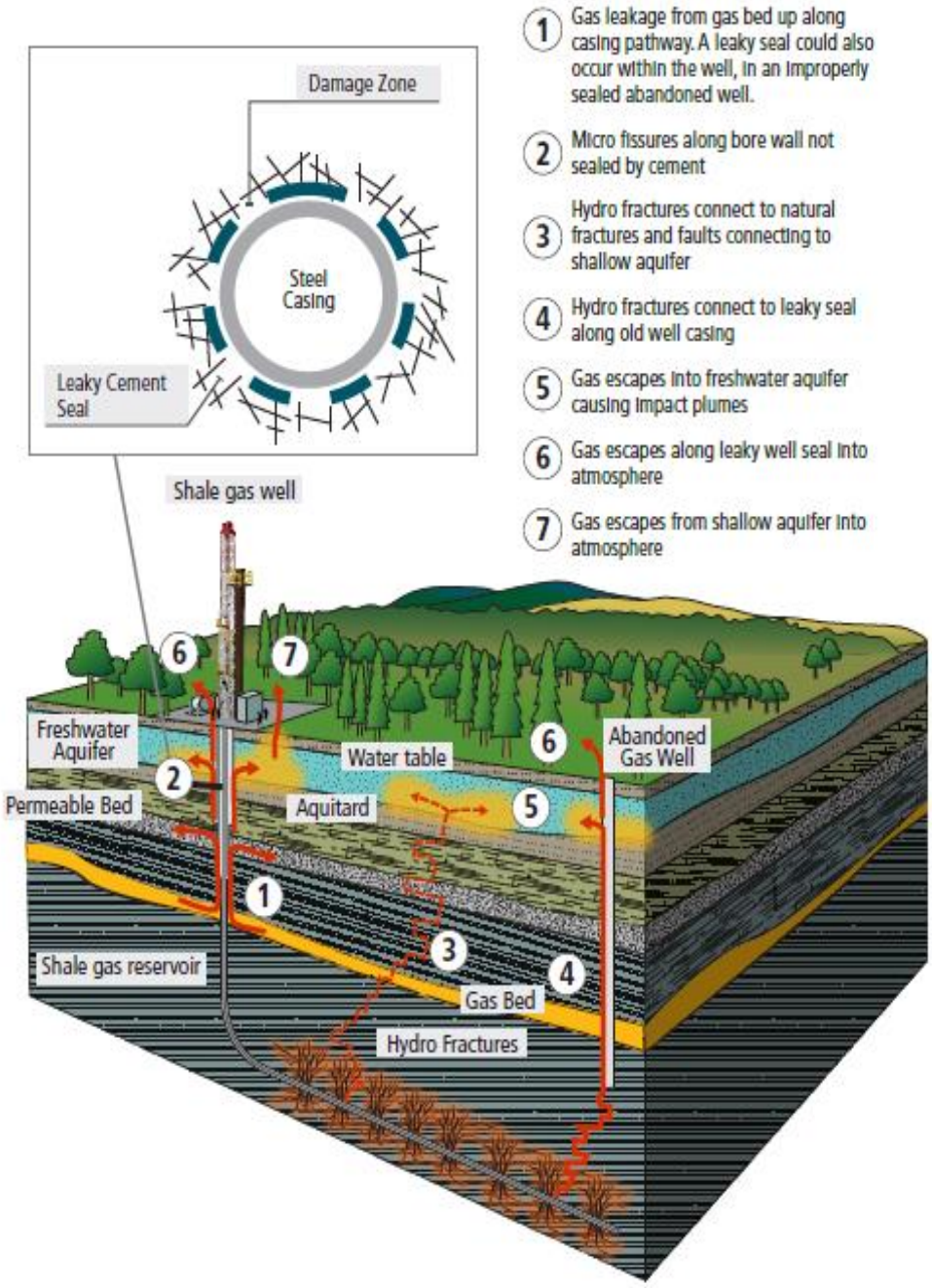

Figure 2.1. Conceptual model of possible pathways for fugitive gas migration (CCA, 2014).

2.2 Literature Review

2.2.1 Gas Migration Pathways: Leaking Wells

Currently, casing leaks are the main pathway for subsurface gas migration (Arthur and Cole, 2014; Darrah et al., 2014; Dusseault and Jackson, 2014). There have been various reports of leaking wells, some of which indicate stray gas migration into shallow aquifers (e.g. Davies et al., 2014; Kelly et al., 1985; Jackson et al., 2013). Stray gas contamination from casings can result from poor cement sealing of the annulus and/or gaps between casings and rock. Pre-existing high-pressure gas from non-target formations may also escape during early stages of drilling, thereby compromising the outer cement annulus and allowing gas to migrate. The cement may also shrink and/or crack after drilling has occurred (and perhaps due to expansion and contraction caused by pressure variations during actual hydraulic fracturing), creating other pathways for gas to migrate through the annulus (Jackson et al., 2013; Vidic et al., 2013; Davies et al., 2014; Dusseault and Jackson, 2014; Soeder et al., 2014).The primary concern with casing leaks is the ability for gas from the intermediate zone and/or production zones to migrate up the annulus to the surface, or out of the casing into the shallow zone, hence affecting drinking water aquifers.

Casing leaks have long been recognized (e.g. McKinley et al., 1973; Harrison, 1983), but only recently surveyed in a comprehensive fashion. Although well drilling practices and technologies are improving, faulty casings remain a concern (CCA, 2014). In 2009, 4.5% of wells in Alberta had gas migration or surface casing vent flows (SCVFs), 98% of which were cased wells (Watson and Bachu, 2009). Between 2005 and 2013, 6.3% of 3533 unconventional wells in Pennsylvania, USA, had well barrier or casing integrity issues (Davies et al., 2014). In British Columbia, it was estimated that 75% of SCVFs were caused by gas migrating from the intermediate zone (Muehlenbachs, 2012 and 2013).

In 1983, Harrison published a paper assessing the risk of groundwater contamination from natural gas drilling in north-western Pennsylvania. He identified three key pathways for subsurface contamination: migration through the borehole annulus, naturally permeable fractures, and abandoned oil and gas wells. The risks of over-pressurizing the annulus and subsequently creating a hydrodynamic gradient were discussed in a subsequent paper (Harrison, 1985), and a recommendation that annular pressure should not exceed normal hydrostatic pressure to reduce the risk of methane gas migration up the annulus and into groundwater. If a permeable pathway exists, contaminants can migrate out the annulus into the aquifer (Harrison, 1985).

A study in Lloydminster, AB reviewed the rate and variability of SCVFs and gas migration from oil and gas wells in the region (Erno and Schmitz, 1996). Although soil gas migration quantification is difficult, the authors used a surface emission open flux chamber to estimate ranges between 0.1 m^3/d and 60 m^3/d. Based on their measurements, gas migration was thought to be mainly limited to within 3 meters of the wellhead. Overall, the authors estimated that 45% of wells had soil gas migration and that 23% presented SCVF (Erno and Schmitz, 1996). However, more distant subsurface gas migration can still occur and not be indicated by soil effluxes, particularly if there is a confining layer. In addition, it seems plausible for gas to migrate farther than 3 meters from the wellhead if a fracture or fault provides a

pathway to the surface. Thus, in a geologically heterogeneous region, multiple methods are needed to monitor and identify pathways of gas migration (CCA, 2014).

Various authors have attempted to understand the pathways of methane migration by identifying fugitive methane sources. For example, Szatkowski et al. (2002) tested and identified the source of SCVFs and soil gas migration using stable carbon isotope analyses from wellbores around Golden Lake Pool, Saskatchewan. A majority of soil samples showed gas migration, and all vent samples indicated SCVFs. Faulty cement casing was thought to be responsible since the fugitive gas appeared to originate from strata above the production zone (Szatkowski et al., 2002). A domestic water well survey used noble gases (^{4}He, ^{20}Ne, ^{36}Ar) to understand the sources of methane in drinking water wells in Pennsylvania, USA (Darrah et al., 2014). The authors compared noble gas and geochemistry of drinking-water wells in the Marcellus and Barnett Shale regions to background groundwater samples. The results suggested that casing faults, from both the production and intermediate zones, were the primary cause of fugitive methane migration into aquifers. Both Szatkowski et al. (2002) and Darrah et al. (2014) provide insight on methods that could be used to identify the composition and source of fugitive gas, which may help to understand the pathways and mechanism. However, it is important to consider that the gas isotopic composition could be altered depending on the transport mechanism (Gorody, 2012; Darrah et al., 2014). Thus, it remains difficult to conclude the true source of fugitive gas.

Numerous publications report similar concerns with oil and gas well casing integrity and cases of associated methane contamination in the shallow subsurface (Van Stempvoort et al., 2005; Watson and Bachu, 2009; Revesz et al., 2010; Moore et al., 2012; Jackson et al., 2013; Rivard et al., 2013; Vidic et al., 2013). Most recently, Dusseault and Jackson (2014) provide a comprehensive review evaluating the causes and risks of casing leaks. An inventory of the events related to global well barrier and well integrity failure is available from Davies et al. (2014).

From the current literature, there is little evidence that abandoned wells, permeable faults, and natural fractures are as significant a pathway as wellbore integrity issues; however, this assessment may change as development increases (Ewen et al., 2012; CCA, 2014). With a higher density of hydraulic fracturing wells in one region, the cumulative impacts could exacerbate unintended well-to-well, or gas-formation-to-fault communication, as well as the volume and rate of gas migration (CCA, 2014; Rivard et al., 2014). For example, when two wells are in close proximity, and target the same geological formation, a pressure pulse from one well can cause water, oil, gas, and/or fracturing fluids to escape and follow the path of least resistance, migrating up another well. In cases where this risk may be present, it is important to assess the depth of abandoned wells, as shallower wells will have lower chances of intercepting permeable flowpaths. An increase in pressure and flow rate can lead to well failures and consequently release hydraulic fracturing and/or formation fluids at the surface (ERCB, 2012). Inter-wellbore communication due to pore-pressure pulses has been observed for wells that are within 4100 m of each other (ERCB, 2012; Dusseault and Jackson, 2014). Relatively recently, Alberta Energy Regulator (AER) introduced a requirement that abandoned wells must have vented caps (Directive 20; AER, 2010). Primarily aimed at preventing pressure build-up in an abandoned well-bore, vented caps also allow observable surface indications of well leakage, which is useful for identifying potential

communication with abandoned wells from hydraulic fracturing operations. Identifying and understanding the pathway(s) of gas migration could help to reduce fugitive gas emissions, and to determine where better drilling practices are needed (ACOLA, 2013; CCA, 2014).

2.2.2 Gas Migration Pathways: Natural Fractures and Faults

Although there is no evidence that permeable faults and natural fractures provide a significant free gas migration pathway, a limited amount of field data exists to assess this possibility. Understanding the constraints on fracture propagation in the context of sedimentary basins is essential in order to gauge the real risk of these potential pathways over time.

As emphasized by Flewelling and Sharma (2014), a sedimentary basin is characterized by the intercalation of various sedimentary rock layers, many of which are typically shale. This creates strong anisotropy, where horizontal permeability is often an order of magnitude greater than vertical permeability. The very presence of gas reservoirs strongly indicates that pathways linking them to more permeable rocks are not innately present. However, the risk posed by introduced pathways to connect gas reservoirs with shallow aquifers, such as stimulated hydraulic fractures connected to natural fractures and faults (Figure 2.1; CCA, 2014), must be taken into account for shallower reservoirs.

Data from fracture treatment indicates that stimulated hydraulic fractures themselves are generally not tall enough to allow connection between the shale gas reservoirs and the shallow aquifers, as their heights usually range from 100 m (Eagle Ford, Woodford, Barnett, Niobrara shales) to 200 m, with few reaching up to 500 m (Marcellus shale; Figure 2.4; Davies et al., 2012). However, hydraulic fracturing operations have been conducted at depths less than 610 m, a good portion of them even less than 200 m, in reservoirs across United States (Figure 2.5; Fisher and Warpinski, 2012). In these cases, hydraulic fracture connections to shallow aquifers must be considered. It is assumed that at shallow depths, namely 500 to 600 m (e.g. Settari and Raisbeck, 1978), the vertical stress corresponds to σ_3 and the thrust tectonic regime would dominate, causing hydraulic fractures to be horizontal (Figure 2.2; Fisher and Warpinski, 2012; Flewelling and Sharma, 2014). As such, they would not connect to shallow aquifers. However, it can be demonstrated that this is an oversimplification of reality from three standpoints. First, when a thrust stress regime is present, shear fractures are typically generated with a dip around 30° (Figure 2.2), which could induce communication between the reservoir and above layers. Second, shallow measurements of the relative magnitude of stresses conducted in Northeastern Alberta suggest that the vertical stress is σ_3, but these measurements are ambiguous and it is not clear how representative they are for the rest of the Western Canada Sedimentary Basin (Bell et al., 1994). Finally, more recent data from Fisher and Warpinsky (2011) demonstrate that the majority of hydraulic fractures initiated at depths from 660 m to less than 200 m are inclined, many of them with dips close to vertical (Figure 2.5). This dip variation is not surprising as near-surface stress regimes (Figure 2.2) can vary abruptly (Talbot and Sirat, 2001; Maloney et al., 2006). Hydraulic fracturing at relatively shallow depth, particularly when there is evidence of steeply dipping hydraulic fracture planes, should be a top priority for addressing the potential connection of the fracturing zone and/or the vertical borehole interval with shallow aquifers.

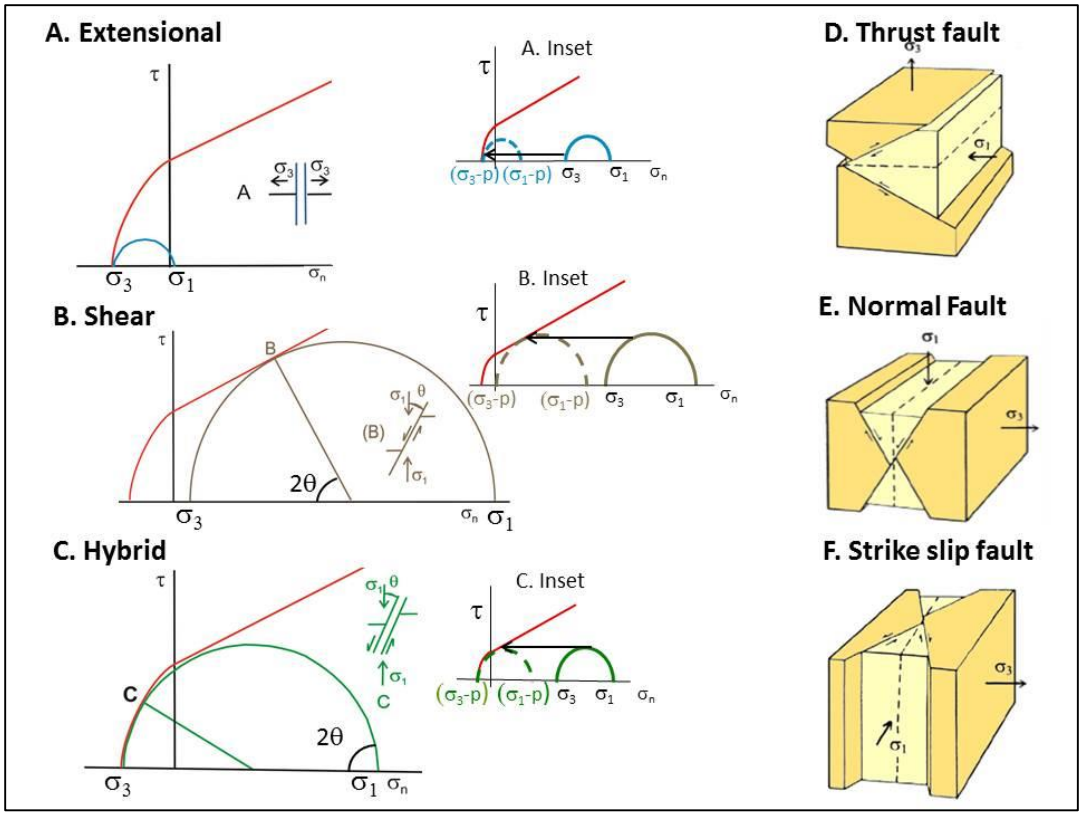

Figure 2.2. A, B and C depict the stress conditions, on a Mohr diagram, that lead to the 3 modes of fracture propagation: A) Opening mode form extensional fractures perpendicular to σ3 and parallel to σ1 (θ is zero degree), B) Shear fractures form at an angle θ of ~ 30° with σ1, C) Hybrid (opening + shear) fractures form at an angle θ less than 30° with σ1. Insets show solid Mohr circles that do not intercept the failure envelope and, in these conditions, fractures are not formed. When the fluid pressure is high enough (overpressure conditions) to drive the Mohr circles to the left (dashed circles), they intercept the failure envelope and hydraulic fractures (either natural or stimulated) will be formed. Usually, hydraulic fractures are thought to propagate only perpendicularly to σ3, by extensional mode, and as such, they would form just one set of parallel fractures. However, as shown in B and C, they can be of shear and hybrid modes and form conjugate fracture patterns. D, E and F depict the 3 stress regimes that lead to 3 types of faults, namely, thrust (D), normal (E), and strike slip (F). Note that opening mode (dashed lines) and shear mode (lines with parallel small arrows indicating sense of slip) are formed in all 3 stress regimes. Opening mode fractures are horizontal (thrust regime) or vertical (normal and strike slip regimes). Shear mode fractures dip at angle of ideally 30° (thurst regime), 60° (normal regime), and 90° (strike slip regime). A conjugate fracture pattern (two fracture sets forming an acute angle of 2θ = 60°) is typical of shear fractures (faults) as shown in D, E and F. A single fracture set is typical of opening mode (extensional) fractures.

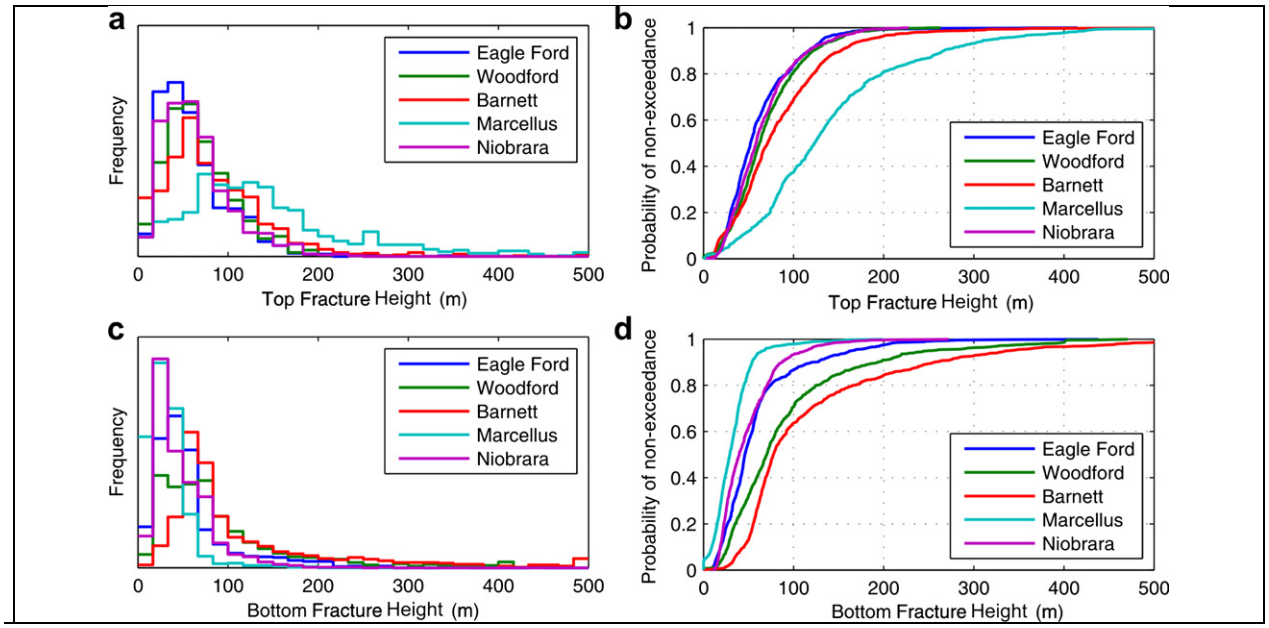

Figure 2.3. Graphs of frequency against hydraulic fracture height for (a) upward and (c) downward propagating fractures in the Marcellus, Barnett, Woodford, Eagle Ford and Niobrara shales. Graphs of probability of exceedance against height of (b) upward propagating fractures and (d) downward propagating fractures. After Davies et al. (2012).

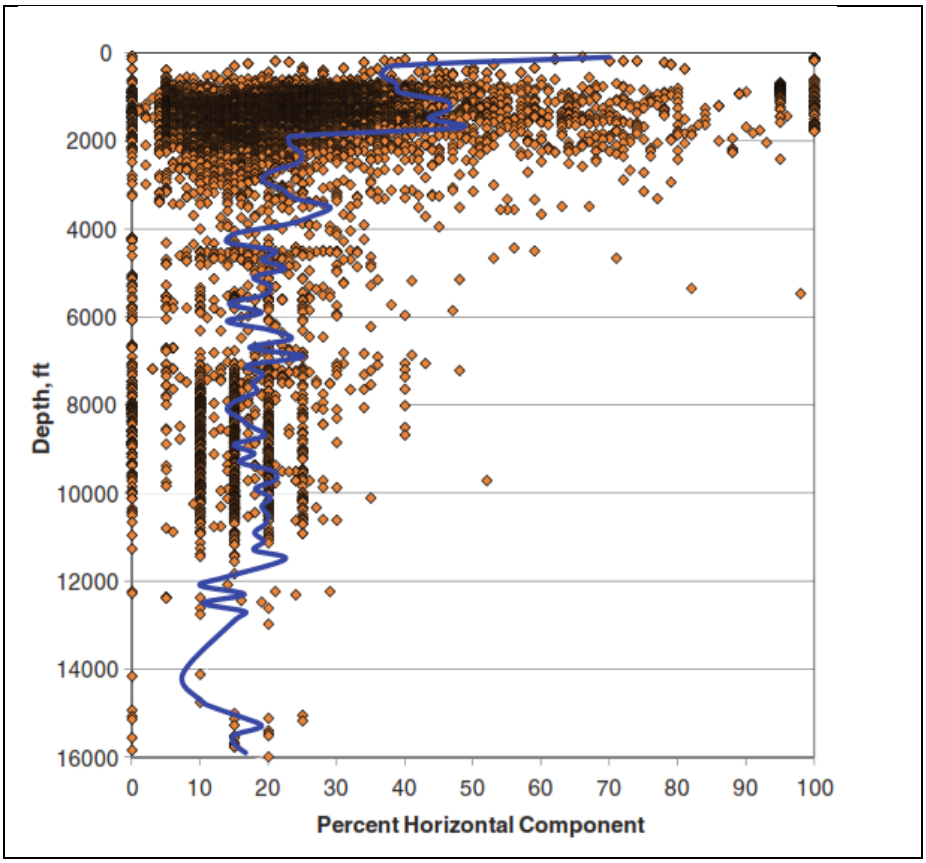

Figure 2.4. Data from surface tiltmeters. Each dot is a separate fracture treatment (10,000 fractures in total). The horizontal scale is the % of fracturing fluid in a single treatment distributed in a given fracture dip, so that 0% fracture component would be a fracture that is vertical, and 100% would be a horizontal fracture. The larger the horizontal component, the less fracture-height growth one would expect. The blue curve is the average of all fracture dips. From Fischer and Warpinski (2012).

Even in the more typical case, in which the reservoir depth is greater than 500 m, it is possible for stimulated fractures to connect with natural fracture networks and/or faults, creating a gas migration pathway to shallow aquifers. In order to analyze the risk of upward gas migration in this situation, one has to consider the geometric characteristics of natural fractures in the shales and overlying sedimentary rocks. In this respect, Gale et al. (2014) conducted a comprehensive review and incorporated new outcrop and core data and reported the following: 1) Subvertical fractures in shale were ubiquitous in the examined cores and outcrops and faults were frequent (present in 13 of the 18 shales); 2) At depth most of the subvertical fractures were sealed, most often cemented with calcite (from core data); 3) Near-surface subvertical fractures were more numerous and mostly absent from outcrop data – many of them were possibly generated by exhumation and uplift processes (Engelder 1985); 4) At least two sets of subvertical fractures were present, usually at high angle to each other and thus favouring connectivity. Although connectivity also depends on fracture heights and lengths, parameters that remain highly uncertain due to limited exposure; 5) The most common geometric subvertical fracture height patterns are bed-bounded and hierarchical (Figure 2.5); 6) Geometric properties, including fracture set orientation, observed at outcrops may or may not correlate to patterns described in core; and 7) Any attempt of extrapolating fracture orientation and patterns to depth should rely on the regional set orientations (e.g. Appalachian Plateau) rather than local fracture sets if possible. Significant natural fracture sets are likely also present in non-shale rocks (e.g., sandstones and carbonate rocks), which are generally considered to be more fracture-prone than shales (Gale et al. 2014).

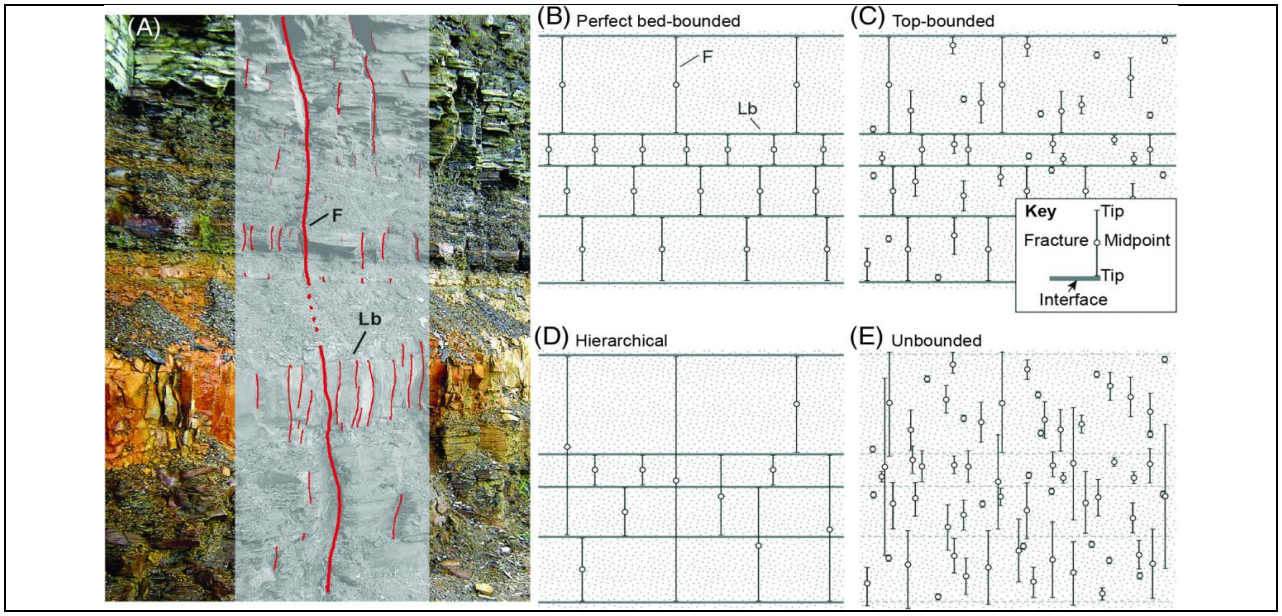

Figure 2.5. Fracture-height classification categories from Hooker et al. (2013). (A) New Albany shale roadcut with hierarchical fracture traces, eastern Kentucky, view northeast. Height of bed below label Lb ~0.5 m (19.7 in.). Overlay shows fracture traces cutting multiple beds (F) and bed-bounded fractures. Lb = bed boundary. (B) Perfectly bed-bounded. (C) Top-bounded. (D) Hierarchical. (E) Unbounded. In shales, although mixtures of height patterns are found, hierarchical and bed bounded are most common in outcrop, and these patterns are compatible with core observations. In Gale et al. (2014).

The great variety of fracture patterns observed is a consequence of the variations of principal stress magnitude and orientation over geological time, variations in lateral and vertical stresses, and mechanical properties in rock such as Young's Modulus, Poisson's number, shear, and tensile strength. These mechanical properties vary with rock type and can cause different timing and mode of fracturing (opening, hybrid, or shear; Figure 2.2; Gross, 1995). This dependence on lithology type is demonstrated by field data, where fractures in homogeneous shales tend to be continuous, while fractures in thinly intercalated shale-siltstone-sandstone tend to be the shortest, as they abut at the frequent lithology interfaces (e.g., Engelder, 1985; Komaromi, 2014). Additional factors contributing to fracture pattern variation are burial and thermal alteration, which can create closely spaced natural fractures in black shale with high organic content (Lash et al., 2004; Engelder et al., 2009).

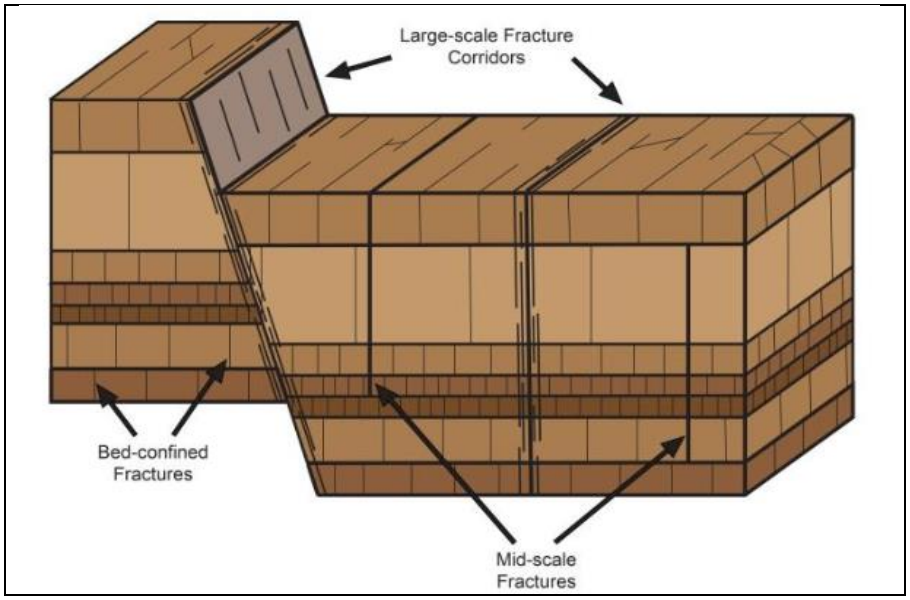

Figure 2.6. Schematic diagram of fracture hierarchy observed in layered sedimentary rocks with different bed thickness. Through-going faults and fracture zones (large scale fracture corridors) are more widely spaced than the more contained fractures (mid-scale and bed-confined). After Gross and Eyal (2007).

Furthermore, increased fluid pressure can drive fracturing in stress conditions that otherwise would not have high enough magnitude to cause fracture propagation (Figure 2.2). Natural hydraulic fracture heights range from centimeters to hundreds of meters, as documented in outcrops (e.g. sand-filled fractures and injectites; Hurst et al., 2011). Davies et al. (2012) show that the maximum vertical extent of natural and stimulated hydraulic fractures is approximately 1000 and 600 meters, respectively, and the probability of exceeding a vertical extent of more than 350 meters is 33% and 1% for natural and stimulated hydraulic fractures, respectively (Figure 2.3).

From the above, we conclude that:

1) Certain fracture properties and patterns may favour upward gas migration, while others may not. For instance, the ubiquitous presence of at least two natural subvertical fracture sets may favour upward gas migration, while characteristics such as bed-bounded fracture patterns and lack of connectivity due to possible small heights and lengths may preclude such migration. Localized pathways might occur along more widely spaced faults and fractures zones (large scale fracture

corridors; Figure 2.6; Gross and Eyal, 2007). Faults, documented in 13 of the 18 shales examined by Gale et al. (2014), tend to be longer and cut through several lithological contacts. Various examples of intersection of faults by hydraulic fracturing activities exist (Davies et al., 2013), and most of the tallest hydraulic fractures are considered to be the result of intercepting faults (Fisher and Warpinski, 2012; Hammack et al., 2014). In some cases faulted areas of the reservoir are specifically targeted because there may be pre-existing fault and fracture permeability (Davies et al., 2013).

2) The widespread infilling of the subvertical fractures at depth does not favour permeability, unless reactivation takes place and causes opening or shear to occur. Gale et al. (2014) comment that calcite, the most common infilling, can have less strength than shale (the host rock), so reactivation can be more likely than growth of new fractures, depending on the orientation of natural fractures with regard to the current stress field (Fossen, 2010). This is even more likely for sandstones, limestones, and dolostones, which are generally more competent than shale, particularly the latter two (Fossen, 2010). Hydraulic fracture treatments can induce shear on pre-existing natural fractures and faults by fluid injection or fluid pressure transmission into fractures (Zoback et al., 2012; Kratz et al., 2012). Tomographic Fracture Imaging (TFI) shows that this may occur at horizontal distances exceeding one km and vertical distances up to nearly one km (Geiser et al., 2012; Lacazette and Geiser, 2013). Hydraulic transmissivity correlates positively with the structures that are favourably oriented to shear or dilation in the current stress field (Barton et al., 1995), and only a small amount of slip (1-2 mm), caused by reactivation, is required to increase permeability in some orders of magnitude (Figure 2.7, Lamontagne, 2001). Unlike natural hydraulic fractures, which can eventually either become tightly closed after being generated (if fluid pressure is reduced) or infilled, stimulated hydraulic fractures are held open by proppant. Thus, communication with reactivated natural fractures and faults could presumably generate permeable flow paths that were previously nonexistent. Again, this type of threat is more plausible in shallower reservoirs and/or when fugitive methane from borehole leaks reach permeable fractures (e.g. Harrison, 1985).

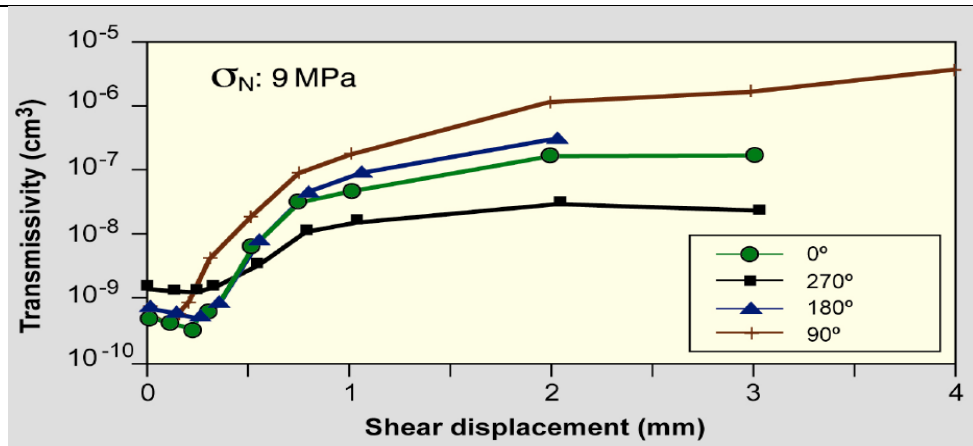

Figure 2.7. Relationship between shear displacement and transmissivity for a given fracture undergoing a normal stress of 9 MPa. With regard to main roughness of the fracture surface, shear occurred in two directions and, in each of them, in two opposite senses (90°, 180°, 0° e 270°) (Lamongtagne 2001).

3) Natural fracture characteristics are better observed in outcrops, but due to common variations of patterns with depth (including fracture set orientations, densities, and the presence of infillings), core and image log data should always be part of the characterization of the fracture network. Since subvertical fractures are commonly contained in the layer in which they initiated (bed-bounded and hierarchical patterns), fracture lengths tend to be much longer than heights. As a consequence, significant lateral gas migration, along the direction of more permeable fractures, is to be expected. In the Western Canada Sedimentary Basin, the more permeable fractures generally trend NE, and locally NW, as these are the directions of the maximum horizontal stress (Bell et al., 1994). Possibly, such plumes may eventually meet connected subvertical fracture networks that can provide a pathway for upward migration. Continued research on this subject should take this into account and use microseismic fracture treatment data from the oil and gas industry in order to determine the orientation of the stress field.

2.2.3 Migration Mechanisms

Identifying the presence of migration pathways, either from leaky wells or connection to natural faults and fractures as discussed above, leads to only partial understanding of methane transport to shallow aquifers. It is important to combine this information with knowledge of the chemical and physical mechanisms of gas migration, a topic that remains a challenge as it requires analysis of multiphase flow patterns and a grasp on how these differ in confined and unconfined aquifers (Figures 2.8 and 2.9, respectively). Although gas production and transport has been observed in the laboratory (e.g. Molins and Meyer, 2007) and in shallow groundwater at contaminated sites (e.g. Amos et al., 2012), relatively little is known about gas transport in groundwater zones at depth (Gorody, 2012; Jackson et al., 2014).

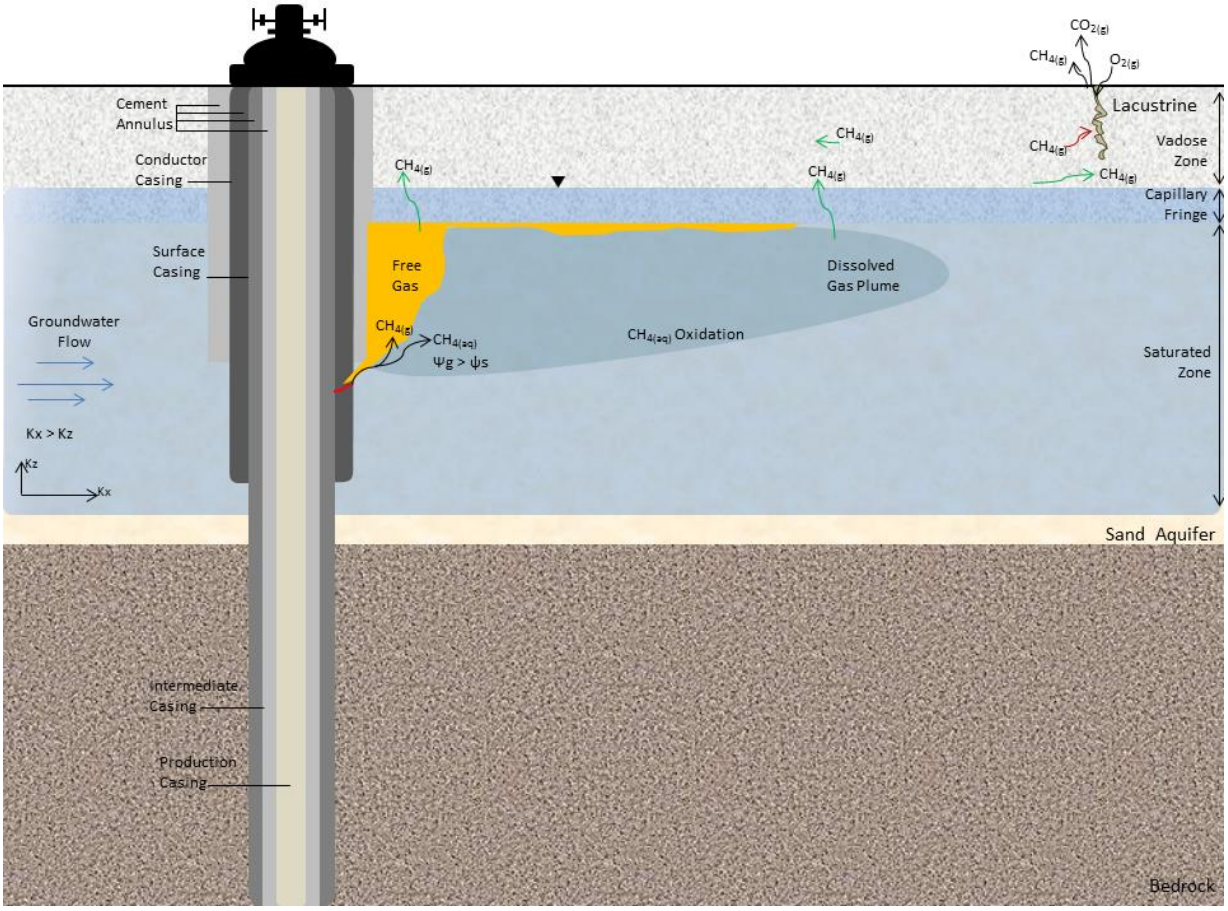

Figure 2.8. Conceptual model of fugitive gas migration into a confined aquifer due to faulty cement along the annulus (adapted from Vidic et al., 2013). Where ψg, the gas pressure, must be greater than ψs, the saturated sand aquifer pressure, for gas to exsolve. Green arrows indicate methane diffusion into the lacustrine deposit and red arrows indicate methane migration to the surface through fractures or faults.

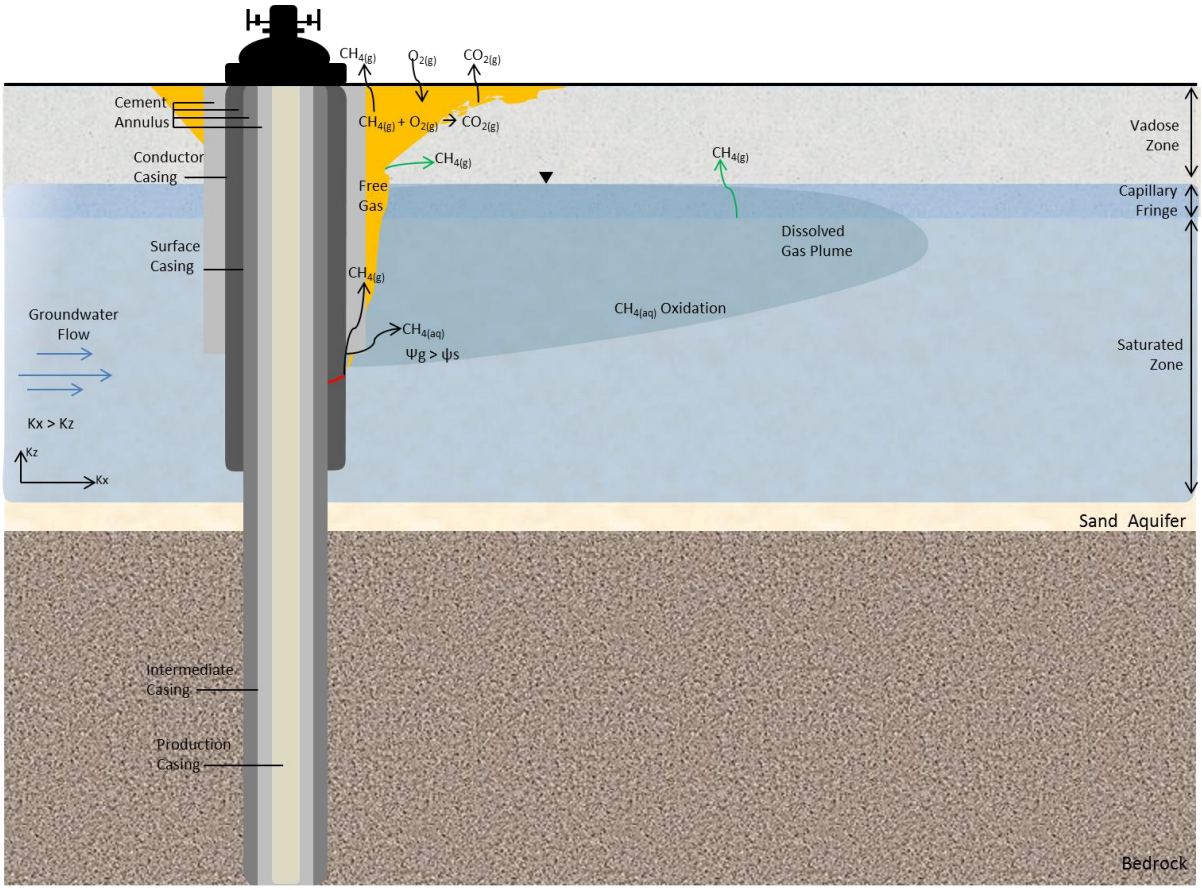

Figure 2.9. Conceptual model of fugitive gas migration into an unconfined aquifer due to faulty cement along the annulus (adapted from Vidic et al., 2013). Where ψg, the gas pressure, must be greater than ψs, the saturated sand pressure, for gas to dissolve. Green arrows indicate methane diffusion into the vadose zone.

Free Gas Migration. Free gas flow in and behind well casings is relatively well understood, with five flow patterns of increasing gas-to-water ratios observed: bubbly, slug, annular, mist, and churn (Lakehal, 2013). As natural gas flows up the casing, decreased formation pressure may lead to increased gas phase volume, which in turn may lead to a transition through these different flow patterns. When free gas migrates up the annulus at high velocities, the small bubbles coalesce to form larger "Taylor" bubbles, which can rise rapidly under buoyancy. This slug flow appears to be the predominant two-phase flow mechanism of fugitive gas within the annulus (Lakehal, 2013).

When free-phase methane migrates from a well casing, it is likely that its pressure will be great enough to overcome the capillary entry pressure of the aquifer matrix. Thus, if a fracture or fault pathway is available, the over-pressurized gas will readily leak into the aquifer and partially dissolve in the groundwater along the free gas pathway (Figures 2.8 and 2.9; Gorody, 2012). Free gas transport will occur if the buoyancy forces of the gas bubbles can overcome the capillary forces (Amos et al., 2006; Gorody, 2012). Understanding the subsurface geology and the extent of heterogeneity is important to determine the governing migration mechanism (Elberling et al., 1998; Sihota et al., 2013).

The free gas transport pattern will be dependent on existing pressure gradients, the formation permeability, and the gas flow/leak rate and volume. In most cases, gas will fill larger pore spaces first, and migrate vertically to the surface. If an impermeable layer prevents vertical migration, pools of gas may form and migrate horizontally, possibly causing the hydraulic conductivity of the aquifer to decline as gas invades pore spaces (Gorody, 2012). Gas may also enter fractures or faults in the overlying formation and arrive at the surface in locations that are hard to predict. Diffusion of dissolved gas into the overlying deposits and away from fractures that have been infiltrated is also expected to occur (Figure 2.8; Vidic et al., 2013).

Literature on migration mechanisms of fugitive methane is limited. However, carbon sequestration storage and coalbed methane research are appropriate for understanding the possible multi-phase flow mechanisms for free phase fugitive gas migration in the subsurface. For example, Seto et al. (2009) investigated the interactions between carbon dioxide and methane upon carbon dioxide injections into a coalbed reservoir system. Carbon dioxide's higher adsorption affinity resulted in desorption of methane, increasing the gas volume fraction and the velocity of the total volumetric flow. In the case of free gas-phase methane migration from hydraulic fracturing, if there are not high carbon dioxide concentrations, methane may adsorb to sediments. On the other hand, if the carbon dioxide concentration and the void fraction are high, methane may freely migrate by slug flow, or another multiphase flow mechanism.

McKee and Bumb (1987) and Valliappan and Wohua (1996) discuss the natural attenuation of methane in saturated coalbed reservoirs. The authors emphasize the importance of considering capillary pressure, porosity, saturation, and permeability in their saturated and unsaturated two-phase flow models. It is possible that these methods of analysis could be used to understand how free gas from hydraulic fracturing will migrate in the subsurface.

Dissolved Gas Migration. Dissolved gas may migrate by molecular diffusion, dispersion, and or advection. The mechanism is dependent on the subsurface environment but will also impact water chemistry and isotopic composition, both of which help to identify and track fugitive gas (c.f. Section 1; Amos et al., 2011; Gorody, 2012; CCA, 2014).

The pathways of dissolved gas can be difficult to identify due to different flow patterns and chemical reactions in groundwater. Depending on the pressure at the point of leakage and the hydraulic gradients, it is possible for flow path reversal to occur or for new flow paths to be created (Harrison 1983; 1985). The fate and behaviour of fugitive methane will also be governed by reaction mechanisms such as oxidation, degassing, and ebullition in the saturated zone. Oxidation mechanisms and rates are dependent on the availability of electron acceptors (Amos et al., 2012; Molins et al., 2013). Furthermore, fugitive gas may be difficult to identify if mechanisms exist to naturally attenuate methane.

Mechanisms of dissolved methane gas migration are better understood than free gas migration, with useful information from field studies of contaminated oil spill sites and landfill leachate sites. For

example, Amos et al. have studied the degradation processes and impacts of a crude-oil spill contaminated site in Bemidji, MN in a number of publications, most recently in 2012. Methanogenesis was the primary degradation pathway for the oil constituents, resulting in a plume of dissolved methane. Entrapment of gas bubbles near the water table due to water table fluctuation induced oxygen transport leading to methane oxidation in the very shallow groundwater (Amos et al., 2012). Similarly, Christensen et al. (2001) demonstrated the importance of redox conditions for natural attenuation in an investigation of the biogeochemistry of landfill leachate plumes.

Recently, Ng et al. (2014) suggested that more methane directly outgasses than dissolves. This study invokes more research on the mechanisms of free gas transport and the coupling of the aqueous phase.

Vadose Zone Gas Migration. Gas migration into the vadose zone could result directly from a casing leak or from free phase gas transport to the water table. An impermeable layer overlaying the unsaturated zone will inhibit upward methane migration and downward oxygen fluxes. This will alter the carbon balance by creating zones of methane plumes in an anoxic environment. However, shallow fractures could allow methane to leak to the surface and/or allow atmospheric intrusion that will create oxygen reactive zones and alter the mechanism of gas migration (Elberling et al., 1998; Amos et al., 2010). Since free gas diffusion is the primary mechanism of gas transport in the vadose zone, aerobic methane oxidation can be seen by high carbon dioxide effluxes at the ground surface (Figure 2.8; Molins et al., 2010; Sihota et al., 2013).

Vadose zone methane transport is reasonably well understood by investigations of volatile contaminants in shallow groundwater zones over the past decades. For example, Elberling et al. (1998) discussed the implications of atmospheric intrusion into a clay-capped unsaturated zone. Cracks or boreholes provide pathways for atmospheric oxygen to enter the unsaturated zone. Vadose zone gas pressure fluctuations and oxygen influxes may influence gas transport. In this case, atmospheric pressure fluctuations led to horizontal gas migration by advection and diffusion. The region of oxygen influx resulted in a reactive zone. The reactivity of this zone was dependent on the permeability of the unsaturated zone, and the time and extent of atmospheric pressure changes (Elberling et al., 1998).

A similar observation was made at the Bemidji site (Amos et al., 2005). Groundwater ebullition into the vadose zone occurred directly above the oil spill plume in the methanogenic zone. The influx of methane to the vadose zone resulted in reaction-induced advective transport, which promoted methane oxidation (Amos et al., 2005). Molins et al. (2013) also demonstrated the importance of gas diffusion transport in the vadose zone. In this study, the authors used a reactive transport model to indicate that advection contributed a limited amount to net gas fluxes and that diffusion was the primary transport mechanism.

Although previous research is informative, it is important to understand the variability and ambiguity behind fugitive methane migration from hydraulic fracturing. More research and data are needed to understand the mechanisms of subsurface gas migration.

2.2.4 Review of National Reports

In addition to peer-reviewed literature, various national reports are reviewed to highlight key concerns with fugitive methane. Three main topics repeatedly appear in these reports:

1. **Lack of baseline data and monitoring.** Initial site characterization and continuous monitoring are essential to understand the subsurface geology and groundwater quality. These data would allow the estimation of the parameters necessary to predict the potential pathways and impacts of methane migration (Ewen et al., 2012; The Royal Society and Royal Academy of Engineering, 2012; ACOLA, 2013; CCA, 2014). Groundwater quality monitoring, in particular, is needed to understand the site-specific assimilation capacity from gas migration (CCA, 2014).

2. **Identifying gas migration.** Each report highlighted the importance of identifying the sources of gas migration from well casing leaks, abandoned wells, permeable faults, and natural fractures (Ewen et al., 2012; The Royal Society and Royal Academy of Engineering, 2012; ACOLA, 2013; CCA, 2014). Ewen et al. (2012) state that well integrity remains an issue and cement leaking will continue to pose the greatest risk for gas migration. Over the next 100 years, it is estimated that 23% of mobilized (not extracted) shale gas could migrate to the surface from the Lünne region. The U.K. Royal Society and Royal Academy of Engineering report (2012) stated that well leakage prevention was crucial to reduce contamination.

3. **Lack of effective monitoring strategies.** Understanding the rate, volume, fate and behavior of fugitive gases is a necessary, yet difficult prerequisite to monitor methane migration (Ewen et al., 2012; CCA, 2014). There is a need for alternate monitoring strategies that detect gas migration from the wellhead and below the ground surface as well as to account for alterations in formation gas and isotopic composition. Gas migration could be detected by developing a gas profile of the vadose zone surrounding the well pad; the spatial scale will depend on the site characteristics. Groundwater wells around the well pad need to be installed and continuously monitored for methane and other contaminants (CCA, 2014).

Overall, the reports concluded that without understanding the pathways of fugitive gases, and without sufficient baseline data, the current methods of water well and gas-sampling will continue to provide insufficient, ambiguous data (Ewen et al., 2012; The Royal Society and Royal Academy of Engineering, 2012; ACOLA, 2013; CCA, 2014).

2.3 Knowledge Gaps

Building off of the issues recognized by the national reports, several knowledge gaps are identified that specifically impede progress on understanding the transport of fugitive gas, which ultimately dictates the subsurface impacts on water quality. These are divided into understanding and information gaps. First, an understanding gap exists in defining of the volume, rate, and composition of gas migration around well pads. Further scientific inquiry is needed to delineate these parameters in various hydrogeological settings, as well as to understand gas migration in the deep zone. Additionally, there is an understanding gap regarding the natural fractures and fault network, specifically in the vicinity of

boreholes. This is relevant for developing conceptual models regarding the interaction of hydraulic fractures with natural geological structures and then defining potential pathways for methane migration towards shallow aquifers.

An information gasp exists in quantifying the number of wells with SCVF and/or evidence for fugitive gas migration. All appropriate wells need to be systematically identified and entered into a nation-wide database, as this could inform appropriate groundwater monitoring approaches to understand fugitive methane transport and water quality impacts in the subsurface.

Another crucial information gap is site specific hydrogeology. The conditions that could lead to gas migration will vary with every site. Characterizing the site hydrogeology will help identify if gas is present and the main mechanisms that dictate gas migration. Currently, in the preliminary phase of research, sufficient and appropriate site selection and access itself remains a challenging task.

Finally, conceptual models in which potential pathways along fractures and faults are depicted depend primarily on the knowledge of: 1) the fracture networks at sedimentary layers that lay between the targeted reservoirs and the shallow aquifers, 2) the tectonic regimes and their variation with depth, which control both the more permeable natural fractures and faults and the attitude of the induced hydraulic fractures, 3) the attitude and location of critically stressed faults, and 4) the mechanical properties of the layers that lay between the targeted reservoirs and the shallow aquifers. These types of information would allow prediction of the possible interactions of induced hydraulic fractures with faults and natural fractures, as well as with faulty casings over the total length of the wellbores.

2.4 Current Research Approaches

There are limited publications discussing current research on the subsurface pathways and mechanisms of methane migration from unconventional hydraulic fracturing. Rivard et al. (2014) discuss various research projects being conducted in Canada. The Quebec Strategic Environmental Assessment (SEA) Committee has partnered with the Université Laval to work on numerical modeling of near-well gas migration, among other projects. Researchers from Simon Fraser University and the BC Ministry of Forests, Lands and Natural Resource Operations are reportedly characterizing groundwater and assessing contamination risks in the Montney region of northeastern BC. The Geological Survey of Canada (GSC) aims to map and assess 30 key aquifers by 2024 (Rivard et al., 2014).

2.5 Range of Research Approaches

Table 2.1a. Range of practical research approaches to address knowledge gaps related to identifying and characterizing gas migration

	Research Approach 1: Measure SCVF and observe for gas bubbling in standing water around wellhead (where present)	**Research Approach 2:** Survey CO_2 and CH_4 effluxes across the well pad with a closed chamber system and use shallow drive points to collect gas samples for composition and isotopic analyses. Conduct multiple well pad long term monitoring using eddy covariance and laser based methods.	**Research Approach 3:** Full site study with sampling points across the well pad with multi-level-wells in the saturated and unsaturated zones; shallow drive points; and closed chamber systems.
Complexity	Low	Moderate	High
Risk/Uncertainty	Stray gas source zone not indicated, nor if there is off-well pad or groundwater migration	Difficult to select survey/sampling points; difficult to determine possible impacts on groundwater	Difficult to apply the results from one site to other sites with different geological properties; not a practical solution for monitoring active sites
Timeframe	Short to moderate; up to a year (longer tests more informative)	Long term; 1-3 years	Long term;
Cost	Low; $100K	Moderate; 300-600K	Moderate to high; 500K – 1M
Research Capacity	High	High	Moderate
Difficulty of Implementation	Low	Moderate; reliable identification of source zone requires subsurface characterization and gas profiling from drilling (currently, most sites do not have this data)	High; land access and approval may be difficult and installation may be challenging
Socio-Political Concerns	Public would likely approve of this but not necessarily understand its usefulness	Public would likely approve of this but not necessarily understand its usefulness	N/A
Likely Achievements	Identify wells with SCVFs and gas bubbling	Characterize local GM across a well pad with surface and subsurface analyses, and large scale GM with surface measurements	Determine mechanism of GM in the saturated and unsaturated zones and possible impacts to groundwater quality

Table 2.1b. Range of practical research approaches to address knowledge gaps regarding understanding subsurface fracture pathways

	Research Approach 1: Compile the orientation and height of individual stimulated hydraulic fractures for the reservoirs at depths less than 700 m	**Research Approach 2:** Collect data on well breakouts which show the orientation on S_{Hmax} and S_{Hmin} at shallow reservoir sites	**Research Approach 3:** Conduct fracture surveys in outcrops of formations that constitute analogues of the shallower gas reservoirs (depths <700 m) and the overlain formations	**Research Approach 4:** Collect natural fracture data in vertical and horizontal wells at shallower reservoir sites (depths <700 m) using core data and acoustic and optical televiewer profiling
Complexity	Low	Low	Moderate	Moderate
Risk/Uncertainty	Low; microseismicity and tilt meter data should be adequate to answer questions at hand	Low; caliper or acoustic televiewer data from vertical part of oil and gas wells should be adequate to answer questions at hand	Extrapolation to target formation depths is not straightforward, well images are needed in order to check whether fracture sets observed at surface can be extrapolated to depth	Data may be limited, particularly with respect to horizontal wells, introducing uncertainty to findings
Timeframe	Short; 6-12 months	Short; 6-12 months	Moderate; 2-3 years	Moderate; 2-3 years
Cost	Low; ~$100K	Low; ~$100K	Moderate; ~100-500K	Moderate; ~200-600K
Research Capacity	High; microseismicity and tilt meter data provided by industry	High; data readily available from industry	High; standard approaches, interpretation not particularly novel	High; data likely collected by industry
Difficulty of Implementation	Low (assuming industry will share data)	Low (assuming industry will share data)	Moderate	High; requires access to appropriate wells before production
Socio-Political Concerns	N/A	N/A	N/A	N/A
Likely Achievements	Identify locations where hydro fractures are the closest to shallow aquifers	Identify natural fracture directions that are more likely to be permeable	Create natural fracture network conceptual models emphasizing how fractures propagate through different lithologies and fracture sets interact with each other	Identify the natural fracture sets that are present in the reservoir and the overlain formations

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SECTION 3: What Are the Geochemical and Water Quality Impacts of Fugitive Methane Migration a) Over Relevant Temporal and Spatial Scales b) On an Aquifer's Attenuation Aapacity?

3.1 Introduction

The use of horizontal drilling and hydraulic fracturing of organic-rich shale formations is increasing rapidly, making the extraction of tightly bound natural gas economically feasible. However, these extraction techniques raise environmental concerns, particularly with respect to the impact of contaminant migration through induced and possibly natural fractures, drilling imperfections, wastewater discharges, and accidental spills affecting water resources (CCA, 2014). Given the large number of private landowners in many rural areas that rely on shallow groundwater for household and agricultural use, it is vital to reliably assess the environmental risk to groundwater quality posed by multi-stage hydraulic fracturing. This section focuses on the current state of knowledge and knowledge gaps regarding water quality impacts of potential fugitive methane (and higher n-alkanes) migration from the production or intermediate zones into shallow groundwater and the attenuation capacity for methane in aquifers.

3.2 Literature Review

3.2.1 Fugitive Methane Migration into Shallow Groundwater

The previous chapters of this report provide an introduction into the occurrence of methane in subsurface environments and potential methane migration pathways. This section summarizes and expands upon this in order to fully discuss fugitive methane impacts on water quality.

Methane is the main component of natural gas and can exist as free gas or in dissolved form. Sources include thermogenic methane in conventional or unconventional reservoirs and in-situ production of biogenic methane in organic matter-rich shallow aquifers, and either of these gas sources or a mixture in the intermediate zone. Deeper thermogenic methane may migrate due to anthropogenic activities such as conventional and unconventional hydrocarbon exploitation (e.g. along imperfectly sealed energy wells), and potentially along natural faults and fractures. It is expected that free phase methane is more mobile due to buoyancy than migration of dissolved methane associated with formation water movement (e.g. Bair et al., 2010; Gorody, 2012).

Methane solubility is controlled by temperature, hydraulic pressure, and salinity (Duan et al., 1992). Concentrations of dissolved methane at atmospheric pressure may range from < 1 mg/L to up to ~30 mg/L, the maximum solubility of methane in groundwater at ~15°C (Jackson et al., 2013). North American federal, state, and provincial drinking water quality standards do not establish limits for methane concentrations in drinking water. However, the U.S. Department of the Interior Office of Surface Mining set criteria to avoid the occurrence of explosive concentrations of methane in indoor air.

They indicate that methane concentrations in water of <10 mg/L is safe, while particular attention is required in the 10-28 mg/L range (at atmospheric pressure), when degassing is possible. Above 28 mg/L, water is usually over-saturated with methane at atmospheric pressure, where a free gas phase is likely and immediate action (e.g. an aeration or similar water treatment system) is needed due to the potential explosive hazard.

If fugitive gases from deeper geological formations (e.g. intermediate or production zones) migrate into shallow aquifers, this may cause changes in gas concentrations and isotopic ratios. Because thermogenic gases generated from Type I and Type II kerogen often contain appreciable amounts of ethane, propane, and higher alkanes, their leakage into shallow aquifers not only increases methane concentrations but also results in the appearance of these n-alkanes in shallow aquifers. Hence, the occurrence of ethane, propane and higher alkanes is a good indicator of intrusion of thermogenic stray gases. Their absence does not necessarily rule out thermogenic gases since Type III kerogen produces dry (i.e. methane-rich) gas (Boyer et al., 2006). Similarly, the gas dryness index (the ratio of methane, C_1, over the sum of higher n-alkane concentrations, C_2 to C_5) is another indicator of intrusion of deeper thermogenic gases, which often have a dryness index <100, whereas shallow groundwater dominated by biogenic methane usually has a dryness index of >1000 (Scott et al., 1994).

A more decisive approach for differentiating thermogenic from biogenic gas are carbon isotope ratios ($\delta^{13}C$), since $\delta^{13}C$ values > -55 ‰ are usually indicative of deeper thermogenic methane, whereas $\delta^{13}C$ values < -60 ‰ are indicative of microbial methane (Whiticar, 1999). Furthermore, hydrogen isotope ratios of methane ($\delta^{2}H_{CH4}$) of < -250 ‰ often indicate biogenic methane, whereas $\delta^{2}H_{CH4}$ of > -200 ‰ are more indicative for thermogenic methane.

In order to use these chemical and isotopic tracer approaches for identifying potential fugitive gas leakage into shallow aquifers, it is of critical importance not only to generate reliable baseline data for shallow aquifers, but also to characterize gas compositions and isotope ratios for the intermediate zone and for shale gas production zones during drilling. A successful example of this approach was published by Tilley and Muehlenbachs (2011). They demonstrated the ability to fingerprint the probable depth of fugitive gas contamination of shallow groundwater from the intermediate zone in a case study in Alberta. Here, a mud gas depth profile was available for an energy well 2.5 km from water wells that had experienced stray gas contamination. Mud gas is the gas entrained in the drilling mud returned to surface and is believed to be representative of the formations the drill-bit penetrates. Figure 1 shows the isotope ratios of methane, ethane, and propane in mud gases from 100 to 650 m below ground surface and in shallow groundwater from three water wells. Matching the carbon isotope fingerprints reveals that the contaminating gas most likely originated from 480-510 m depth, suggesting that stray gas leakage occurred from the intermediate zone and not from the production zone. The compilation of mud gas depth profiles for chemical and isotopic compositions is thus of critical importance to have sufficient baseline data for estimating depths of potential stray gas leakage.

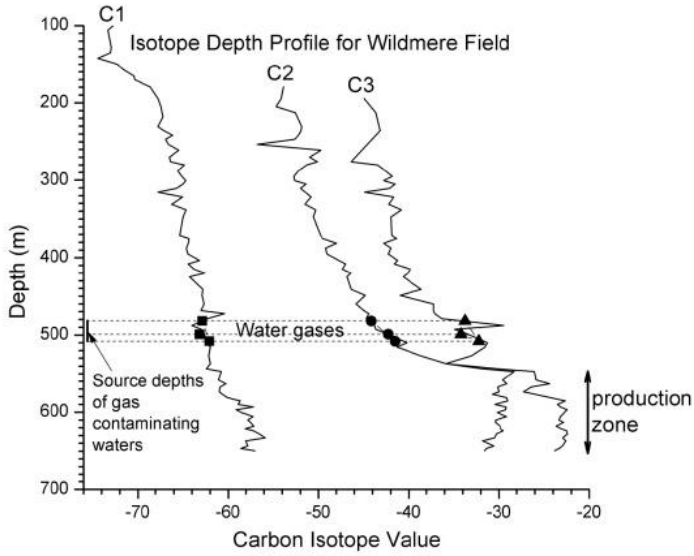

Figure 3.1: A mud gas depth profile from a case study in Alberta showing the depth of fugitive gas contamination of shallow groundwater from the intermediate zone (Tilley and Muehlenbachs, 2011).

Thermogenic gases from shale gas plays in North America are usually found deeper than one kilometer and have even more distinct chemical and isotopic signatures than those shown in Figure 1. Produced gases from the Horn River Shale (Upper Devonian), the Doig formation, and the Montney formation (Lower to Middle Triassic) have average $\delta^{13}C_{CH4}$ values of -31.2, -38.5 and -39.7‰, respectively (Tilley and Muehlenbachs, 2013). A survey of gas wells across western and central New York found that gas from wells reaching Upper and Middle Devonian formations had an average $\delta^{13}C_{CH4}$ value around -44.9‰ while wells reaching Lower Devonian or Silurian formation produced gas with a totally different signature around -36.3‰ (Jenden et al., 1993). Although the chemical and isotopic compositions of production gasses are usually determined by industry, the data are not shared. It would be ideal if these values could be made publicly available for tracing the depths of stray gas leakage where applicable.

It is important to realize that the isotopic signature of fugitive gases may change during migration, potentially compromising the ability to track the origin of stray gas leakage. A study by Osborn and McIntosh (2010) pointed out that migration processes such as diffusion may cause changes in $\delta^{13}C$ values. In this study, thermogenic methane derived from Devonian age organic-rich shales and reservoir sandstones across the northern Appalachian Basin margin assumed a biogenic isotope signature (Bernard, 1978), suggesting that $\delta^{13}C$ values had decreased during migration from depth (Prinzhofer and Pernaton, 1997). Microbial oxidation of methane also has the potential to affect the $\delta^{13}C$ values of the remaining methane (Barker & Fritz, 1981), and hence these processes must be taken under consideration while using stable isotope data for identification of depths of stray gas leakage.

Mixing between multiple gas sources can also modify the concentration and isotopic composition of fugitive methane. This can complicate the unique identification of the depths of stray gas leakage (Barker and Fritz, 1981).

The objective of monitoring programs should be to collect sufficient baseline gas concentration and stable isotope data for shallow groundwater, the intermediate zone, and the production zone to effectively trace fugitive methane migration into shallow aquifers after completion and hydraulic fracturing of energy wells.

3.2.2 Geochemical and Water Quality Impacts of Fugitive Methane

A number of recent studies have investigated the occurrence, or the lack thereof, of fugitive methane in groundwater (Osborn et al., 2011a and b; Kresse et al., 2012; Warner et al., 2012, 2013; Darrah et al., 2012, 2014; Jackson et al., 2013; Molofsky et al., 2013; Vengosh et al., 2013; 2014; Li and Carlson, 2014; McPhillips et al., 2014). These studies focused mainly on the distribution and origin of methane in groundwater using geochemical and isotopic approaches, but the impact of fugitive methane on groundwater quality remains poorly investigated and documented. Despite differences in local geological and hydrogeological characteristics, land-use histories, industry practices, and monitored water contaminants, the gas composition and C and H isotopes ratios of methane usually enable differentiation between shallow biogenic and deep thermogenic methane. Whereas some studies in Pennsylvania found increased concentrations of dissolved methane in groundwater within the proximity of shale gas wells (Osborn et al., 2011a; Jackson et al., 2013), two others studies in the same region found no evidence of increase methane in drinking-water wells as a result of drilling of wells into unconventional natural gas plays (Boyer et al., 2012; Molofsky et al., 2013). One of these studies noted a few instances of water quality changes such as increases in TDS, bromide, chloride, sodium, barium concentrations from pre- to post-drilling conditions, which were related to drilling fluids rather than stray gas impacts (Boyer et al., 2012). In the Fayetteville shale region of Arkansas, geochemical investigations did not find evidence that methane and major ion chemistry in shallow groundwater had been influenced by shale gas activities (Kresse et al., 2012; Warner et al, 2013).

The Council of Canadian Academies report (CCA, 2014) showed that the literature on groundwater impacts has grown markedly in the past three years, though the data are generally limited to water well sampling and commonly do not support definitive conclusions. Several recent studies of methane in shallow groundwater have attempted to relate its occurrence with topography, hydrogeological conditions, geochemical water types and redox conditions (Van Stempvoort et al., 2005; Darling and Goody, 2006; Molofsky et al., 2013; McPhillips et al., 2014). A recent study in Pennsylvania by Molofsky et al. (2013) found no relation between dissolved methane in groundwater and gas well distance, but found elevated methane concentrations in groundwater sampled in valleys and in sodium chloride or sodium bicarbonate type groundwater. In central New York State, McPhillips et al. (2014) also found a correlation between methane concentration and water types with elevated dissolved methane concentrations in groundwater dominated by sodium chloride or sodium bicarbonate. This suggests that the elevated methane concentration is associated and controlled by bedrock interactions along deeper flow paths and lengthy groundwater residence times.

The combination of major ion geochemistry, methane concentrations, C and H stable isotope ratios, and noble gases is particularly powerful to identify stray methane sources and transport mechanisms (Darrah et al., 2014). Not only are noble gases are conservative (i.e. not affected by biochemical

reaction in groundwater), their isotopic compositions can be used to source them from the crust, hydrosphere, and atmosphere. This approach was successful identify four areas where well water methane was sourced to production gases from the intermediate zone, either through failures of annulus cement, production casings, or in one instance to a faulty gas well.

A major water quality impact of fugitive methane is its potential impact on the redox state of the affected aquifers. For instance, the oxidation of methane may be associated with the reduction of oxidizing reactants, such as dissolved oxygen, nitrate, nitrite, manganese, iron, or sulfate. The extent to which methane oxidation occurs depends in part on the dominant terminal electron-accepting process in the aquifer (Weidemeier et al., 1999). One potential consequence of changes in redox conditions is the increase of the solubility of redox-sensitive species such as iron, manganese, arsenic and other trace metals, which have the potential to deteriorate the groundwater water quality. Moreover, the bacterial reduction of sulfate to sulfide (e.g. H_2S) through anaerobic bacteria is another process with the potential to impact water quality negatively (Van Stempvoort et al., 2005; Vidic et al., 2013; Fontenot et al., 2013). However, it is important to note that such negative impacts on groundwater quality are highly dependent on the mineralogical composition of the aquifer matrix, and hence site-specific assessments are required.

Besides the question of sufficient baseline data (both temporally and spatially), the Council of Canadian Academies report (CCA, 2014) stated that the important issue concerning groundwater impacts of shale gas development is not just whether such impacts occur, but whether these impacts become significant enough to be unacceptable. To address this question, long-term monitoring records are necessary to fully distinguish between changes in water quality due to potential stray gas leakage and natural variability associated with mineralogical heterogeneity, climate, and other factors.

3.2.3 Aquifer Attenuation Capacity

The Council of Canadian Academies report (CCA, 2014) stated that the fresh groundwater zone can strongly attenuate many types of contaminants. These mechanisms occur over distances and timescales that vary depending on the contaminant and the characteristic of the hydrogeological systems. For the attenuation of fugitive gases in shallow aquifers, an understanding of natural flow systems, including flow direction, velocity and groundwater residence times, can help to predict the spatial and temporal development of the dissolved methane plume. Attenuation may occur by dilution of the plume and hydrodynamic dispersion. In addition, physical-chemical processes such as adsorption and biogeochemical reactions (e.g. microbial methane oxidation) within the aquifer can efficiently attenuate methane. Redox processes including bacterially mediated methane oxidation can play a significant role in controlling dissolved methane concentrations. The identification and assessment of rates (e.g. kinetics) of methane attenuation processes require a detailed understanding of the overall geochemical characteristics of the studied aquifer including redox environment, degree of confinement, etc. Furthermore, redox reactions are best studied with multi-level piezometers rather than landowner wells. Also, the Council of Canadian Academies report (CCA, 2014) stated that if there are some attenuation processes, the fact that the methane concentration decreases does not necessarily mean that the water quality improved if one considers all aspects of suitability for domestic water uses.

3.3 Knowledge Gaps

The previous sections address current knowledge about water quality impacts of potential fugitive methane migration from the production or intermediate zones into shallow groundwater and the attenuation capacity for methane in aquifers. Based on the Council of Canadian Academies report (CCA, 2014) and this CWN report, information and understanding gaps have been identified and are listed below. Information gaps relate to the lack of data (input and/or output data) whereas the understanding gaps refer to the lack of understanding of mechanisms and processes related to the obtained data. These gaps are organized in a similar sequence as the previous sub-sections.

Fugitive methane migration into shallow groundwater

The CCA report (2014) identified the issue of insufficient baseline information for shallow groundwater. Here, information and understanding gaps are posed as specific questions that, if answered, may address this larger knowledge gap.

- *Which parameters should be analyzed in priority?*
  This refers to the number of parameters that should be analyzed to establish a complete and efficient baseline database. A standardized list of minimum required testing parameters should be established.

- *How often is it necessary to sample baseline groundwater to fully capture natural variability in methane concentrations?*
  A single groundwater sample may not be enough to understand the natural methane variability (spatial and temporal) in shallow aquifers. Multi-analyses may need to be carried out to have more information about methane variability that are either inherent to the aquifer conditions *e.g.* variations in the gas or water fluxes, variation in the water-gas equilibrium, pressure and temperature changes or extrinsic to the aquifer conditions *e.g.* sampling/pumping, analytical causes, the fugitive methane intrusion.

- *Is it better to analyze dissolved or free gas phases and how can sampling methods be standardized to achieve comparable results?*
  Methane concentration is one of the analyses required by the baseline testing programs. However, the regulations through different provinces and states in North America are not consistent regarding the free or dissolved gas sampling and analyses. Some of the regulations require methane in its dissolved form (*e.g.* Colorado or Pennsylvania), others in its free gas phase (*e.g.* gas water separation in Alberta; Alberta Environment, 2006). Appropriate sampling techniques to collect representative groundwater samples of dissolved or free gas should be selected and documented. A range of sampling approaches was discussed in Section 1.

- *Are landowner wells suitable monitoring tools or are dedicated monitoring wells needed?*

Obtaining high quality and representative samples is fundamental to not misinterpret the obtained data and this relates partially to sample access, reliability and density of existing wells (landowners) versus scientific monitoring wells (c.f. Section 1).

- In addition, it is essential to obtained improved and more widespread knowledge on the composition, distribution and isotopic composition of mud gases throughout the intermediate zone.

For the intermediate zone, information and understanding gaps include answers to the following two questions:

- *Which parameters should be considered in the mud gases profile?*
  The concentrations and carbon isotope ratios of gases such as methane, ethane and propane and their variations with depth have been shown to be highly valuable parameters derived from mud gases. It is necessary to evaluate and standardize the parameters which should be recorded during energy well drilling and find a procedure to make such data accessible.

- *How can the sampling and analytical procedures during drilling and mud gas monitoring be standardized to achieve comparable results?*
  Mud gas monitoring systems and analyses often lack standardization and stringent QA/QC procedures and hence further efforts are required to establish procedures that yield comparable results.

Regarding the produced gases, there is no real information gap besides ensuring availability of results that are typically subject to industrial confidentiality.

For dedicated monitoring programs in shallow aquifers the following knowledge gaps were identified.

- *Are additional analytical parameters required and feasible for routine use, or only needed in special cases?*
- Additional parameters such as noble gases were reported previously as highly desirable to better constrain the origin of fugitive gas and migration mechanisms into shallow aquifers. It is thus important to provide more recommendations about their integration in the monitoring program. Moreover, the spatial and temporal variability of methane transport could be evaluated if the flow in the relevant aquifer system(s) and relative residence time are known. These parameters are important for monitoring well placement and to track dissolved methane plumes. This prompts the following question:

- *What is the state/degree of the target hydrogeological systems knowledge?*

Finally, based on efficient monitoring approaches a remaining question is:

- *How extensive are changes in chemical and isotope compositions of n-alkanes gases during transport processes?*
  Transport mechanisms of gases such as methane and higher n-alkanes require more research regarding potential changes of the isotopic fingerprinting. This is important to help in the overall understanding of the fate and transport of methane and other n-alkanes.

Water quality impact

Once fugitive methane has impacted a shallow aquifer, health-related guidelines (e.g. for metals) are clear, but aesthetic impacts are less clear. Thus information and understanding gaps include the following:

- *In case of water-quality evolution linked to fugitive methane migration, what is the acceptability limit for non-health related parameters?*
  A proper aquifer characterization is necessary to assess the potential vulnerability of the aquifer in case of a potential fugitive methane intrusion.

Aquifer attenuation capacity

For shallow groundwater, knowledge gaps include the following questions:

- *What is the methane assimilation capacity of shallow aquifers and what factors can be used to predict it?*
- *What are the natural attenuation breakdown pathways, daughter products, and reaction rates for methane?*

3.4 Range of Research Approaches

Three research approach examples are provided here to address some directions to the knowledge gaps formulated in the previous section.

Table 3.1. Range of practical research approaches to address knowledge gaps.

	Research Approach 1: Long-term geochemical and isotopic monitoring of methane during baseline sampling on an observed well	**Research Approach 2:** Qualification and quantification of water-quality evolution and attenuation capacity related to fugitive methane migration into shallow aquifer and through controlled experimentations	**Research Approach 3:** Comparing geochemical and isotopic approaches between landowners wells and dedicating monitoring wells
Complexity	**Case A:** Low to moderate; long-term record (>10 years) of gas geochemistry and isotopic composition already in the acquisition system of existing database **Case B:** Moderate to difficult; selection of the observation well and long term record to obtain and collect gas geochemical and isotopic data	**Case A:** Moderate; laboratory experimentations **Case B:** Difficult; field site pilot →different hydro-chemical and geological settings	Moderate; based on the implementation of the dedicated monitoring and the sampling methodology
Risk/ Uncertainty	Moderate; complexity/quality of pumping, sampling and analytical procedures → uncertainty on the representative sample/data of the aquifer conditions in both cases	Moderate/high; Accessibility, authorization of filed site and integration in a numerical modeling approach	Moderate
Timeframe	**Case A:** Short; consider only the interpretation <1 year **Case B:** Long; >10 years to collect and obtain the data on existing observation well	**Case A**:Long; Years **Case B**: Long; > 3 years at minimum	Long; > 3 years at minimum
Cost	**Case A**: Low **Case B**: Moderate to High	**Case A**: Low **Case B**: Moderate to High	High depending on the equipment/characteristic of the dedicated monitoring well
Research Capacity	**Case A**: Moderate; 1*HQP to interpret data **Case B**: High; >1*HQP including field and analytical skilled personnel	**Case A & B**: High; >>2*HQP including field, experimental, analytical and modeling skilled personnel	High; >>1*HQP including field and analytical skilled personnel
Difficulty of Implementation	**Case A**: Low **Case B**: Moderate	**Case A**: Low **Case B:** Moderate to High	Moderate to High

Socio-Political Concerns	Public likely in favour of better knowledge of water resources	Public acceptability on the field site	Public likely in favour of better knowledge of water resources and quality of the water well implementation
Likely Achievements	Assessment of the natural and temporal variability of key parameters for fugitive methane migration detection (ideal case > 1 well for spatial variability appreciation and integration)	Geochemical and isotopic monitoring tools for fugitive methane intrusion detection, importance/negligible water-quality evolution. Spatial and temporal scales integration (case B)	Information on the quality of sample obtained and recommendation on the future sampling campaign on existing wells

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SECTION 4: How Can Models Most Effectively Be Developed and Applied to Understand Fluid and Gas Migration, and the Consequences of Contamination?

4.1 Introduction

One of the major concerns of developing unconventional gas reservoirs relates to hydraulic fracturing and/or activities related to gas extraction which may pose risks to subsurface drinking water resources by creating high permeability transport pathways that allow hydrocarbons and other fluids (fracturing and formation fluids) to escape (e.g., BAPE 2011; The Royal Society and Royal Academy of Engineering, 2012; Ewen et al., 2012; ACOLA, 2013; Jackson et al., 2013; Vidic et al., 2013; CCA, 2014; CEES, 2014). Fluid migration rates are usually extremely slow in deep sedimentary basins, and therefore migration of contaminants from the shale gas formation to a shallow aquifer may only be possible if hydraulic fracturing and/or activities related to gas extraction (such as well construction and cementation) induce communication with other conductive pathways. As stated in several reports and papers (e.g., BAPE 2011; The Royal Society and Royal Academy of Engineering, 2012; Jackson et al., 2013; Vidic et al., 2013; CCA, 2014; Davies et al., 2014), the two most probable conductive pathways for the leakage of fluids to the surface are: 1) permeable natural fractures and faults, and 2) leaky wellbores. Depending on the characteristics of the fractured reservoir (over the life cycle of shale gas development, i.e., hydraulic fracturing, production, and after abandonment), these pathways may allow for migration of gases and possibly saline fluids over short and long time scales, with potentially significant cumulative impacts on aquifer water quality.

A common and very useful approach for understanding and predicting short and long-term behaviour of fluid migration in subsurface systems (i.e., gas, formation fluids and fracking fluids) is the mathematical modelling of fluid flow and mass transport. As stated by Ewen et al., (2012), *"A model helps us to gain greater insight into complex events or phenomena that occur over an extended period and for which relatively little empirical data are available - for example for long-term safety or very deep underground areas*." Mathematical modelling has been and still is the main approach used to predict the long-term performance of geological repositories for high-level nuclear waste (Alley and Alley, 2013). However, for a numerical simulator to accurately describe the subsurface migration of gas and fluids in the context of shale gas, several important processes have to be included. Four of the most important processes are defined here: 1) During hydraulic fracturing, depending on the fracking pressure and on the mechanical properties and age of the rock, fractures can develop and propagate to different distances within the shale formation (up to several hundred meters; Davies et al. (2012)). Hydro-mechanical processes, which include propagation of fractures and the temporal variation of reservoir hydrodynamic properties (e.g., fracture permeability) during and after gas extraction, should be taken into account in numerical models; 2) Shale formations contain gas, brine, fracking fluid and sometimes oil, constituting a multi-phase multi-component flow system (with coupled flow and thermal effects). The multi-phase multi-component nature of flow, real gas (not ideal) behavior at high pressure and temperature, Klinkenberg effects (on gas permeability) in low permeability formations, and transport mechanisms (i.e., advection, mechanical dispersion and molecular diffusion) are important factors that should be considered; 3)

Thermal differentials and heat transfer between shale gas reservoirs and groundwater should be included as they affect fluid viscosity, density, buoyancy, gas and mineral solubility, and, consequently, the rate of fluid migration; and 4) chemical reactions involving methane and components of the hydraulic fracturing fluids such as biodegradation, ion exchange and sorption, under equilibrium or kinetic conditions, should also be included. Additionally, depending on the adopted conceptual model, most of these processes should be considered simultaneously as they are often inter-dependent and can induce coupled effects between the flow system, transport system, thermal and mechanical regimes.

Over the past two decades, significant advances have been made in modelling complex systems, including non-isothermal multiphase systems (mixtures of gases and aqueous and non-aqueous phase liquids), heterogeneous and fractured media, and biogeochemical reactive transport. However, there is currently no single numerical approach that simultaneously includes the most important thermo-hydro mechanical and chemical processes which occur during the migration of gas and fluids along faults and leaky wellbores. This knowledge gap is evident in that to date, only single phase numerical simulators for flow and transport have been applied in the limited number of published modelling studies addressing the possible migration of contaminants (i.e., formation and fracking fluids) along preferential pathways in the context of unconventional hydrocarbon development.

4.2 Literature Review

A literature review revealed two knowledge gaps associated with modelling: (1) knowledge gaps related to the ability of models to accurately simulate relevant processes and (2) knowledge gaps related to input and calibration data necessary for simulation and validation. Each of these issues is discussed and clarified in the following sections.

4.2.1 Models to Date

Due to lack of information or lack of ability of models to simulate simultaneous flow of gas and formation fluids, existing models have included significant simplifications. For example, Gassiat et al. (2013), in their generic modelling to assess the impact of hydraulic fracturing on the migration of fracking fluids to shallow aquifers along natural (pre-existing) faults, used a single-phase multi-component water-saturated flow model and considered the impact of hydraulic fracturing by a uniform increase in permeability of the entire hydrofractured zone. Kissinger et al. (2013) assessed the impact of hydraulic fracturing on the migration of fracking fluids to shallow aquifers along natural faults in the Lower Saxony Basin and the Münsterland Cretaceous Basin in the state of North-Rhein Westphalia, Germany. In their site-specific study, the gas reservoir was not explicitly included in the model. Instead, it was replaced, using a conservative assumption, by a boundary condition for the geological layers which lay above it. In addition to this simplification, the authors only considered the migration of brine and fracking fluid and neglected the migration of methane (either as a gas or dissolved phase) in their fluid mixture. Nowamooz et al. (2013 and 2014; in review) applied a multi-phase flow and multi-component numerical model to assess methane and brine leakage rates and associated migration time scales along the cemented casing of a hypothetical decommissioned shale-gas well. Their simulations were intended to quantify the possible effects of poor casing cementation and to identify the critical combinations of parameters that may lead to significant gas release to shallow aquifers from

decommissioned shale gas wells. Although the multi-phase multi-component nature of flow was considered in this work, the impact of hydraulic fracturing was taken into account only by considering a higher permeability for the entire shale formation, which would not accurately represent the targeted section of a discretely-fractured reservoir. Moreover, inertial and Klinkenberg effects (on gas permeability) due to low permeability of the shale and overlying formations were neglected in this work, and the discrete fractures were represented using an equivalent porous medium.

The previous analyses and summaries revealed that there is a strong need for the improvement of modelling tools which predict the migration of gas and fluids along faults and leaky wellbores. Moreover, if the impacts of shale gas development on groundwater quality are to be understood through simulation, simulators capable of coupling gas and fluid-phase migration with dissolved-phase geochemical reactions processes will have to be developed. This has not been done to date, likely because it is an immense challenge with respect to both computation resources and data acquisition issues. Therefore, future subsurface migration modelling should make use of coupled thermo-hydro-mechanical-chemical models, with the objectives of: 1) determining whether the hypothetical preferential migration pathways (faults and leaky wellbores) are physically and geo-mechanically possible during field operations and resource development and, if so, identifying the range of conditions under which fluid migration is possible, and 2) exploring and explaining how contaminant properties, fluid pressure, and local geologic properties control migration mechanisms and affect the possible emergence of contaminants in an aquifer.

It is important to note that depending on the nature of the studied problem, only the most relevant thermo-hydro-mechanical-chemical processes need to be considered in order to decrease computational costs, difficulties and uncertainties (See Table 4.4 for several examples). However, oversimplification (e.g. neglecting the fundamental physical and chemical processes) can result in unrealistic conclusions and should be avoided.

In addition to modelling limitations, uncertain input parameters and the lack of field data for verification of models are also of concern. As stated by CCA, (2014), *"mathematical models predicting the leakage and long-term cumulative impacts of hydraulic fracturing are unreliable due to the uncertain parameter inputs required, simplifying assumptions, and lack of field data for verification. Due to the lack of necessary field characterization data, models will not reliably predict long-range or long-term impacts of shale gas development on regional groundwater resources"*. Quantitative assessments of the impacts of shale gas extraction by means of mathematical models are therefore only possible if adequate input parameters and reliable field data (observations) are available for model calibration or at least model verification.

4.2.2 Input and Calibration Data

A literature review revealed that the mechanical (c.f. Section 2) and hydrodynamic properties (permeability, porosity, dispersivity) of the fractured reservoir (as a source of gas and contaminants) as well as properties of the preferential pathways (wellbore and/or faults) are not yet fully defined. In case of geochemical modelling, input parameters such as the initial formation water chemistry, its oxidation

state, and initial abundance and distribution of selected hazardous trace elements are not always available. To fill this important data gap, a complete research program should combine laboratory and short- and long-term field investigations and experiments.

Reliable field data on the short- and long-term cumulative impacts of hydraulic fracturing have not yet become available to calibrate and verify numerical models. Moreover, much of the limited data that exist in the literature is still being debated in scientific circles. For example, in their study of 68 private groundwater wells in Pennsylvania and New York, Osborn et al. (2011) found evidence of methane contamination and concluded that it was likely caused by methane migration through existing conduits or due to leaky well casings. Using isotope analysis, the authors argued that methane contamination of water wells in active areas was likely from deep thermogenic methane sources, whereas biogenic or mixed biogenic/thermogenic sources were the cause for methane occurrences in shallow aquifers. Molofsky et al. (2011, 2013), however, argued that data from the same area indicated that the natural gas present in water was not isotopically similar to the Marcellus Shale gas that had originated from hydraulic fracturing, but rather to shallower formations. Schon (2011) pointed out additional limitations of the Osborn study, particularly with respect to a lack of baseline data.

There is therefore a lack of established test sites where short- and long-term monitoring of deep and shallow groundwater would help identify the impacts of shale-gas extraction activities. These field data provide the observational data essential to advance conceptual and mathematical models for understanding and predicting impacts on larger spatial and temporal scales.

Three types of data should be provided by these field experiments and monitoring tests which would improve the reliability of numerical models in this context. The first type concerns the baseline or background hydrogeochemical conditions of groundwater flow systems. The second type concerns the impacts that the gas and brine can have on fresh groundwater resources. The third type concerns the rates of methane and brine leakage from leaky wellbores and faults into aquifers and rates of leakage at ground surface. The first and second include data on geochemical and microbial processes that can attenuate in-situ natural gas contamination (including reaction by-products) and the third mostly involves physical processes.

4.3 Knowledge Gaps

1) There is currently no single numerical model that simultaneously includes the most important thermo-hydro mechanical and chemical processes that occur during the migration of gas and fluids along faults and leaky wellbores.

2) There is a strong need for the improvement of modeling tools which predict the impact of hydraulic fracturing on the migration of gas and fluids along faults and leaky wellbores. Objectives of future subsurface migration modeling should be determined by means of coupled thermo-hydro-mechanical-chemical models applied to understand whether the hypothetical preferential migration pathways (faults and leaky wellbores) are physically and geomechanically possible during field operations and resource development. If so, the models should be subsequently used to identify the range of

conditions under which fluid migration is possible, and exploring and explaining how contaminant properties, fluid pressure, and local geologic properties control hypothetical migration mechanisms and affect the possible emergence of contaminants in an aquifer.

3) Geo-mechanical rock properties and hydrogeological properties of the fractured reservoir as well as properties of the preferential pathways are not yet fully defined.

A complete mathematical modeling research program should be combined with relevant laboratory and short- and long-term field investigations and experiments to provide data for model calibration and validation.

To conclude, advanced new models that include coupled geo-mechanical and multi-phase flow and reactive processes are needed together with reliable field data for model calibration and testing. To this end, test sites need to be established where deep and shallow groundwater can be monitored to improve process understanding and to help detect the impacts of shale-gas extraction activities.

4.4 Range of Research Approaches

Table 4.1. Range of modelling research approaches.

	Research Approach 1: Development of modelling tools which predict the propagation of fractures and the temporal variation of reservoir hydrodynamic properties during and after gas extraction	**Research Approach 2:** Numerical study of the migration of contaminants along natural fractures and faults and along leaky wellbores considering non-isothermal multi-phase, multi-component flow	**Research Approach 3:** Numerical study of the effect of fluid and gas migration on groundwater quality and chemistry	**Research Approach 4:** Study the effect of hydraulic fracturing on pressure perturbations at the local and regional (basin) scale	**Research Approach 5:** Collection of reliable laboratory and field data to calibrate and validate numerical models
Complexity	High; Hydro-mechanical model	High; Thermo-hydrodynamic model for fluid/gas flow and transport	High; Thermo-Hydro-reactive model	Moderate; Hydrodynamic model	Moderate; Laboratory experiments High; Field monitoring
Risk/ Uncertainty	Reliable log interpretations, core analysis, and micro-seismic data are needed	Reliable rock, fluid and wellbore properties are needed.	Reliable initial water chemistry, oxidation state, reaction rates and initial distribution of selected hazardous trace elements are needed.	Reliable rock and fluid properties and HF conditions are needed.	Dedicated and expensive equipment is needed.
Timeframe	Long term; 3-5 years	Long term; 3-5 years	Long term; 3-5 years	Long term; 3-5 years	Long term; > 5 years
Cost	Moderate; $70,000-300,000	Moderate; $70,000-300,000	Moderate; $70,000-300,000	Moderate; $70,000-300,000	Moderate to high; $500,000-1,000,000
Research Capacity	High; Collaboration with industry	High; Solid knowledge of thermo-hydrodynamic processes	High; Solid knowledge of chemical reactions	Moderate; knowledge of hydrodynamic processes	High; Collaboration with industry
Difficulty of Implementation	High	High	High	Moderate	High
Likely Achievements	Mechanical and hydrodynamic properties of reservoirs over the complete life cycle of shale gas development	Whether hypothetical preferential migration pathways can develop over the complete life cycle of shale gas development	Assessing the potential impacts on drinking water resources in cases of fluid migration	Assessing the effect of pressure perturbations during and after hydraulic fracturing on the local and regional scale	Data necessary for calibration and validation of models

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SECTION 5: What Mechanism(s) Cause Induced Seismicity? How Can Critically Stressed Faults Be Identified and Avoided?

5.1 Introduction

As shale gas development grows, risks associated with hydraulic fracturing garner increasing concern. One possible impact of hydraulic fracturing is induced seismicity and the related risk to critical infrastructure such as dams and power generating stations. Cases of felt earthquakes proved to be associated with hydraulic fracturing have been reported in Canada, USA, and the UK (Green et al., 2012; B.C. Oil and Gas Commission, 2012 and 2014; Holland, 2013; Skoumal et al., 2015), with maximum magnitude of 4.4 (in local magnitude, ML) reported in the Fox Creek area, Alberta (AER, 2015).

Hydraulic fracturing is one of several mechanisms responsible for generating induced earthquakes; other types of fluid injection such as long-term wastewater disposal, enhanced oil recovery, and CO_2 sequestration can also cause induced seismicity. Thus, there has been extensive research on this topic in the past decades (e.g. Davis and Frohlich, 1993; Baranova et al., 1999; Shapiro and Dinske, 2009; Holland, 2013; Davies et al., 2013; Goertz-Allmann and Wiemer, 2013; Keranen et al., 2014), but a full understanding of the nature of induced events remains elusive and requires detailed knowledge of the relation between injection parameters, geology of the area, and mechanisms of fault-slip triggering.

In this report we review the following knowledge gaps in the context of induced seismicity and hydraulic fracturing:

a) What is the relation between hydraulic fracturing and induced seismicity?
b) How can critically stressed faults be identified and avoided?

5.2 Literature Review

5.2.1 Relation Between Hydraulic Fracturing and Induced Seismicity

Although the physics of earthquakes are generally well-understood, the mechanisms of induced seismicity are still in debate. Several factors including injection parameters, pre-existing faults, reservoir permeability, and the ambient stress field are necessary to study induced seismicity in a particular region.

The first cases of felt induced earthquakes (as detected by seismometers) were associated with wastewater injection at the Rocky Mountain Arsenal in the 1960s (Evans, 1966; Healy et al., 1968). The first reported felt events from hydraulic fracturing, however, occurred near Blackpool, UK in 2011 (Green et al., 2012; Clarke et al., 2014). To date, the largest induced event from long-term wastewater disposal by underground injection wells was the November 2011 Mw 5.6 earthquake near Prague, Oklahoma (Keranen et al., 2013). The largest event associated with the hydraulic fracturing stage of shale gas was the January 2015 ML 4.4 Fox Creek, Alberta earthquake (AER, 2015). Despite the operational differences between wastewater injection and hydraulic fracturing, initiation of shear slip on fault planes can be explained by the Mohr-Coulomb model (Figure 5.1, Davis and Pennington, 1989; Nicholson and Wesson, 1990; Davis and Frohlich, 1993).

Generally speaking, tectonic earthquakes occur on pre-existing faults at lithospheric depths (also known as seismogenic depths) where brittle behavior of materials leads to sub-surface rupture. The source mechanism of earthquakes is mainly determined by the orientation of principal stress components (σ_1, σ_2, σ_3) at depths where $\sigma_1 > \sigma_2 > \sigma_3$. Figure 5.1a shows the maximum and minimum components of principal stress for two common stress regimes under which failure can occur. On the left-hand panel the stress condition leads to reverse/thrust faulting where maximum (compressive) principal stress is near horizontal. Depending on the frictional strength and the effective normal stress on the fault plane ($\sigma_1 - p_f$ where p_f is fluid pressure), failure occurs once shear stress on the fault (τ) has been exceeded. On the right-hand panel, the stress condition for normal faulting is shown where maximum principal stress is vertical (IEAGHG, 2013). In order to understand the mechanism of fracture and effect of pore/fluid pressure in a compressive medium, we use the Mohr-Coulomb diagram.

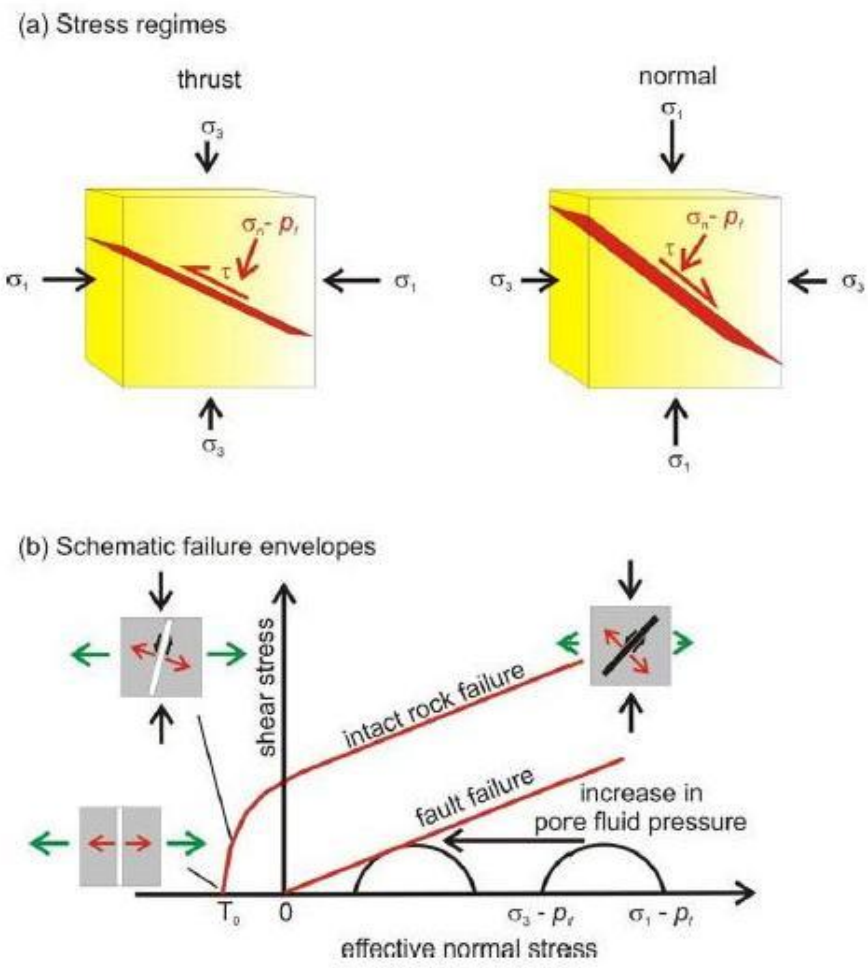

Figure 5.1. (a) Two of the common stress regimes acting on the crust (b) illustration of the Mohr-Coulomb diagram (IEAGHG, 2013).

Figure 5.1b is an illustration of the Mohr-Coulomb diagram showing failure lines for pre-existing faults (with zero cohesion) and intact rocks. As pore pressure increases the Mohr circle shifts to the left and eventually intersects with the failure lines leading to new fractures. On Figure 5.1b we can identify two

distinct failure regimes. Shear failure occurs on the right-hand side of the diagram where the slope of failure lines is linear (high effective normal stress). Tensile fractures occur on the left where effective normal stress is very low (causing hydrofracturing with open crack formation; IEAGHG, 2013).

Where the fluid pressure causes an effective stress that leads to the formation of new fractures, hydraulic fractures can propagate by (1) opening mode, orthogonally to the minimum principal stress, σ_3, and in the direction of maximum principal stress, σ1; (2) hybrid mode at an angle of less than 25° with σ1; or (3) shear mode at an angle around 30° with σ1. The direction of the latter two depends on the stress regime (Fig. 2.2). For horizontal wellbores parallel to the reservoir strata, hydraulic fractures often propagate vertically and can reach to hundreds of meters upward. Figure 5.2 shows a schematic diagram of natural and stimulated hydraulic fractures.

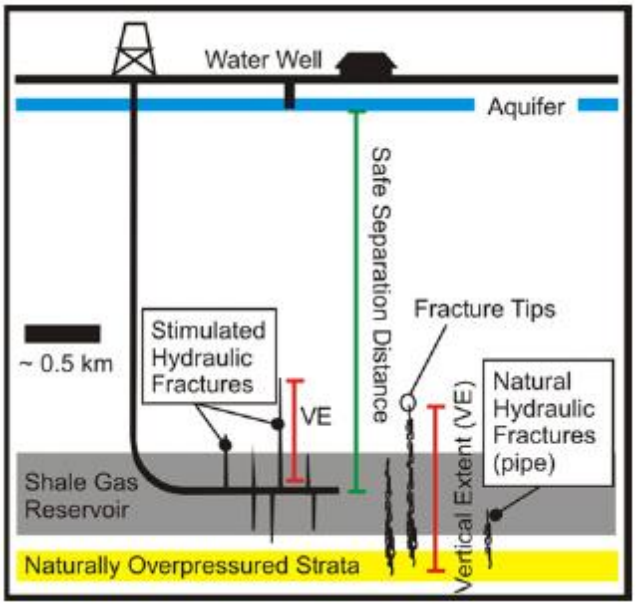

Figure 5.2. Schematic diagram showing natural and stimulated hydraulic fractures (Davies et al., 2012).

Although there may be a direct relation between injection volume and time period of each hydraulic fracturing stage and size of fractures (Davies et al., 2012), geomechanical properties and bedding thickness also play an important role in fracture propagation as this can put an upper limit on the size of hydraulic fractures (Maxwell, 2011). Davies et al. (2012) compiled datasets of natural and stimulated hydraulic fractures in a variety of geological settings. They observed that the maximum vertical extent of natural and stimulated hydraulic fractures is approximately ~1000 and ~600 meters, respectively. They also concluded that the probability of exceeding a vertical extent of more than 350 meters is 33% and 1% for natural and stimulated hydraulic fractures, respectively. Rather than being a single fracture, locations of microseismic event clouds suggests that these fractures are probably formed from a smaller system of fractures (Davies et al., 2012). Microseismic monitoring of hydraulic fracturing operations is essential to identify unusually tall fractures.

Generally, earthquakes that are related to hydraulic fracturing are very small microseismic events (between -3.0 to -0.5; Holland, 2013). A major concern is the possibility of larger earthquakes being triggered due to the injection of large volumes of fluid. Goertz-Allmann and Wiemer (2013) proposed a geomechanical approach to forward-model the induced seismicity response to a hydraulic injection in space and time (Figure 5.3). To calibrate the model they used the observed seismicity of the Basel geothermal stimulation. Their results show that the probability of exceeding a certain magnitude is larger after geothermal well shut-in and the largest events can occur hundreds of meters from the injection point. The results from this simulation can be coupled with field data to study seismic hazard from hydraulic fracturing in real time.

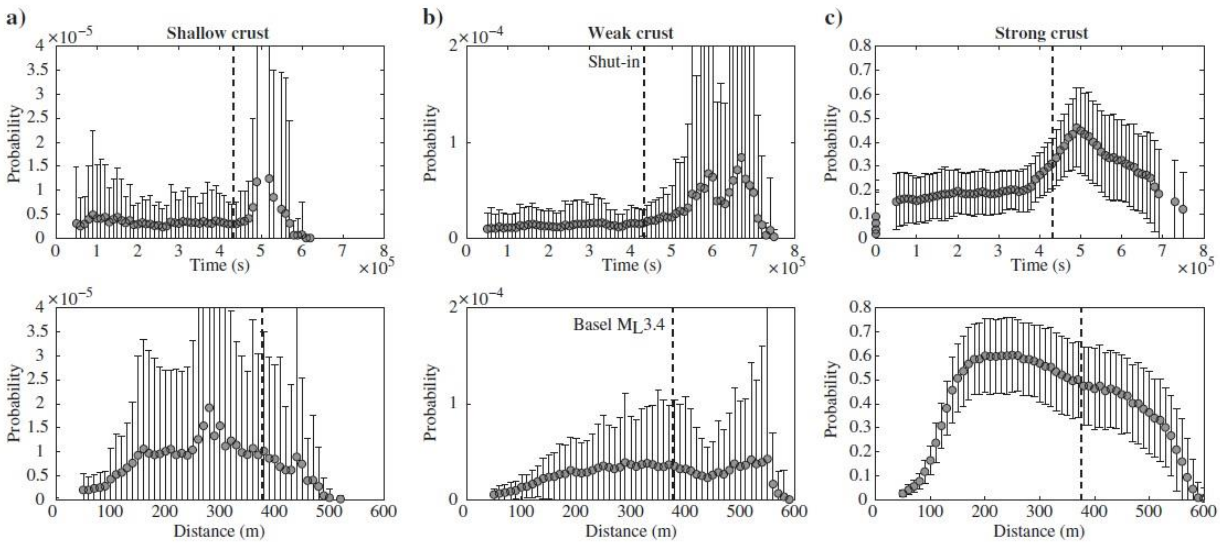

Figure 5.3. Probability of exceeding a magnitude 4 event to occur at a certain time (top row) and distance from the injection point (bottom row). Three crustal models are considered in the simulation; a) a shallow crust model at 2.5 km depth, b) a weak crust model, and c) a strong crust model. Error bars show the standard deviation computed from 100 model runs. The dashed line marks the shut-in time, and the location of the largest observed Basel event in distance from the injection point. From Goertz-Allmann and Wiemer (2013).

Davies et al. (2013) emphasized that after hundreds of thousands of hydraulic fracturing operations, only very few examples of felt seismicity have been documented, and that the likelihood of inducing felt seismicity by hydraulic fracturing is relatively small compared to mining, oil and gas field depletion, reservoir impoundment, enhanced geothermal system, and wastewater injection. The seismicity related to hydraulic fracturing is generally low magnitude and monitoring must involve deploying sensors a few hundred metres of the hydraulic fracturing, using downhole geophone strings, in order to be able to detect the tiny events related to fracture growth and fault reactivation. Earthquakes with magnitudes larger than expected for fracture propagation, and responsible for the felt seismicity, indicate reactivation of a discrete and critically stressed fault.

Another important aspect regarding mitigation of hazard in hydraulic fracturing operations is the protocols that provide guidelines on the continuation or cessation of the operations after the occurrence of abnormal events. Several regulatory bodies and industry partners including Alberta Energy Regulator, BC Oil and Gas Commission, Canadian Association of Petroleum Producers, and UK Department of Energy and Climate Change have proposed guidelines and monitoring systems to assess the risk of induced seismicity from hydraulic fracturing. The current traffic light system in UK considers magnitude 0.5 and higher as the threshold for cessation of the injection (UK Department of Energy and Climate Change, 2013), while in Canada the B.C. Oil and Gas commission and Alberta Energy Regulator require suspension of the operations in case of any seismic event with magnitude 4 or higher within a 3 km radius of the drilling pad or any event felt at the surface within this radius (B.C. Oil and Gas Commission, 2014; AER, 2015). Operators are encouraged to deploy dense seismograph arrays in order to be able to monitor the injection in real time and to be able to take required actions accordingly.

While using magnitude in traffic light systems can help mitigate the seismic hazard from moderate magnitude events it does not allow assessing the risk associated with abnormal ground motions from smaller magnitude events. Magnitude measurements are not representative of the level of shaking at individual sites since they represent the energy released at the source of the earthquake. Similar magnitude events recorded at similar distances can show different level of ground motion depending on the geology of the path and materials below the structure (Babaie Mahani and Atkinson, 2013). Therefore, knowledge of parameters such as attenuation and amplification of seismic waves in the region where injection is taking place and the surrounding area is crucial to calculate the risk from ground motions at individual sites.

5.2.2 Critically Stressed Faults

Pore pressure diffusion through natural pathways (such as faults or bedding planes) to critically stressed faults is the proposed mechanism for felt triggered seismicity related to fluid injection (Green et al., 2012; B.C. Oil and Gas Commission, 2012; Holland, 2013; Clarke et al., 2014). Prior knowledge of regional faults in the vicinity of hydraulically fractured wells, along with their orientation in the stress field, can give insights regarding the possibility of triggering fault slips. Earthquake focal mechanisms and wellbore breakouts represent information that can be used to identify the current stress field and principal stress components in the region (Hurd and Zoback, 2012). Actions can be taken through bypassing stages adjacent to a known active fault (B.C. Oil and Gas Commission, 2012). Imaging techniques such as seismic reflection and electrical resistivity prior to the initiation of hydraulic injection and microseismic plots during hydraulic fracturing operations can shed additional light on the subsurface geology and help to delineate natural pathways for pore pressure to reach the critically stressed faults at distances from the injection point. On microseismic plots obtained during hydraulic fracturing operations, faults can sometimes be seen as linear swarms or a smaller bundle of events with a large signature event represented by a large dot. On microseismic vertical profiles (such as the example shown in Figure 5.4), faults can also be observed as long trailing legs of dots (B.C. Oil and Gas Commission, 2012).

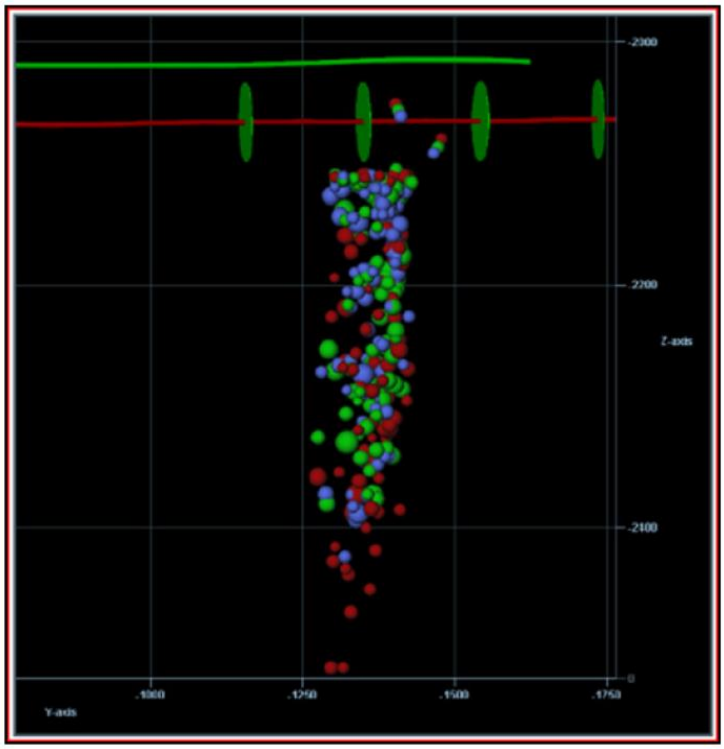

Figure 5.4. Microseismic vertical profile from hydraulic fracturing operations in Horn River Basin, BC. Microseismic events (coloured circles) and hydraulic fracture stages (green ellipses) along horizontal wellbore legs are shown. (B.C. Oil and Gas Commission, 2012).

Davies et al. (2013) proposed three mechanisms for induced seismicity due to fault reactivation:

1. Fracturing fluid or displaced pore fluid can enter the fault.
2. Direct connection with the hydraulic fractures, so a fluid pressure pulse is transmitted to the fault.
3. Due to poroelastic properties of rock, deformation or inflation from hydraulic fracturing fluid injection can increase fluid pressure in the fault or in fractures connected to the fault.

They also proposed the following pathways for fluid or a fluid pressure pulse:

1. Directly from the wellbore
2. Through new, stimulated hydraulic fractures
3. Through pre-existing fractures and minor faults
4. Through the pore network of permeable beds or along bedding planes

There are several methods that can be used to identify fault reactivation during hydraulic fracturing. Plots of magnitude versus distance from monitoring stations can reveal clusters of events with larger magnitude than expected which is indicative of fault reactivation. Figure 5.5 shows such a plot for hydraulic fracturing operations in the Jonah Field, USA (Davies et al., 2013).

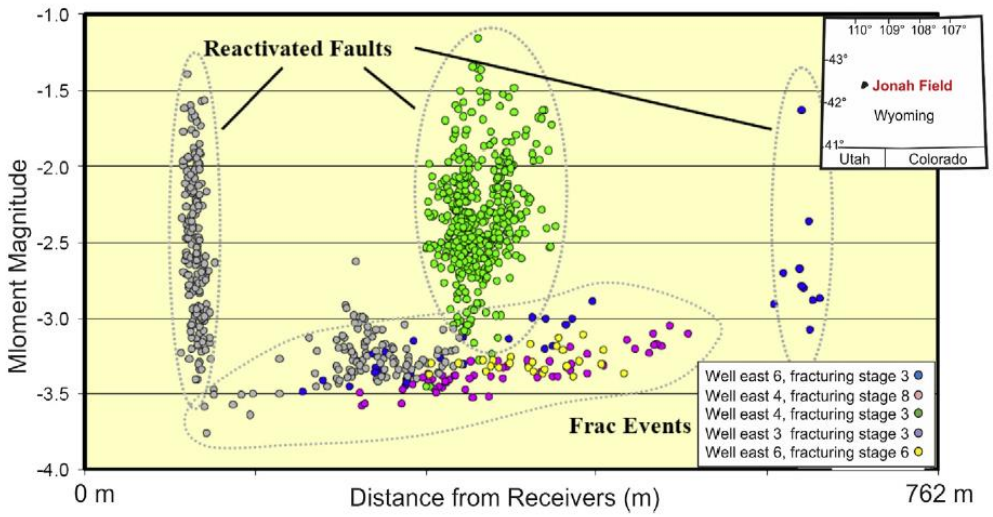

Figure 5.5. Plot of moment magnitude versus distance from seismic stations for hydraulic fracturing operations in Jonah Field, USA. **Clustering of events with larger magnitude is indicative of fault reactivation. From Davies et al. (2013).**

An increase in the magnitude of microseismicity with time after the start of injection is usually another indication of fault reactivation (Davies et al., 2013). The increase in magnitudes of induced events can be accompanied by reduction in the b-value (slope in Gutenberg-Richter plots). This analysis can be done during the operation and can be used as a powerful method to monitor fault reactivation, although care is needed to ensure that the calculated b-value is accurate (Alexander et al., 2014).

In cases where critically stressed faults are misaligned with the stress field, some workers have suggested that slow slip may occur on faults, resulting in Long-Period-Long-Duration (LPLD) events (Das and Zoback, 2013a and 2013b). Figure 5.6 shows an example of LPLD events in Barnett shale in Texas. It should be noted, however, that care is required for interpreting LPLD events, as often these can be confused with local earthquakes (Caffagni et al., 2015).

Finally, Eaton and Babaie Mahani (2015) have noted inter-regional differences in which hydraulic fracturing appears to be a more significant cause of fluid-injection induced seismicity in western Canada compared with large volume wastewater disposal, the dominant triggering mechanism in the U.S. These differences may arise due to proximity of injection to crystalline basement, or differences in the state of stress in different sedimentary basins.

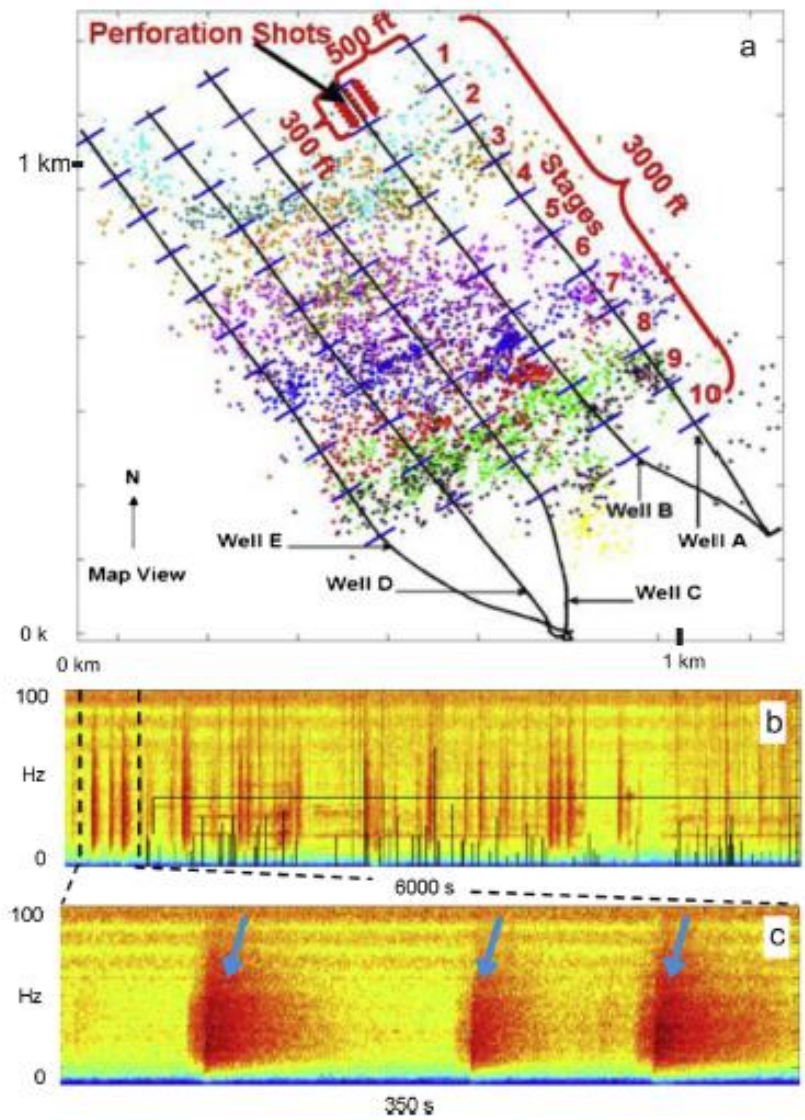

Figure 5.6. Long-Period-Long-Duration (LPLD) events from hydraulic fracturing operations in Barnett shale in Texas. a) Geometry of the wells and reported seismicity. b) Axial spectrogram of stage 7 of wells A and B showing numerous LPLD events. c) Examples of LPLD events for frequencies below 100 Hz taken from b). Blue arrows show the LPLD events. From Davies et al. (2013).

5.3 Knowledge Gaps

Two knowledge gaps are considered here in the context of hydraulic fracturing and induced seismicity. Although hydraulic fractures have been documented to extend to hundreds of meters in vertical extent, in the majority of monitored treatment the spatial distribution of microseismicity suggests that event clouds are formed from smaller fracture systems rather than a single one. Fault reactivation is probably the cause of felt induced seismicity from hydraulic fracturing. Critically stressed faults can be triggered through increase of pore pressure on the fault plane, reducing the effective normal stress and initiating shear slip. The orientation of these critically stressed faults in the current stress field must be known in order to analyse the stability of the fault planes. Some workers have proposed that faults that are

misaligned in the stress field can undergo slow slip in the form of Long-Period-Long-Duration (LPLD) events. Real time monitoring of hydraulic fracturing using down-hole geophone and surface broadband arrays can be used to analyse the response of the reservoir to the stress disturbance caused from high-pressure fluid injection.

5.4 Range of Research Approaches

Table 5.1. Range of practical research approaches to address knowledge gaps

	Research Approach 1: Seismological methods to study seismicity related to hydraulic fracturing including hypocenter determination, moment and stress tensor inversion	**Research Approach 2:** Coupled hydrogeology and geomechanical modeling of fault slip
Complexity	Moderate	Difficult
Timeframe	Low; 1-2 years	Moderate; 3-5 years
Cost	Low; $50-60k	Low; $100-150k
Research Capacity	Moderate	High
Difficulty of Implementation	Moderate	High
Additional Considerations	Requires waveform data from dense arrays usually provided by operators	Requires injection parameters from operators
Likely Achievements	Better understanding of seismicity related to hydraulic fracturing	Provide guidelines on how fluid injection changes the local stress regime at reservoir depths and on the adjacent fault planes that might be triggered as a result of injection

Seismological methods to study seismicity related to hydraulic fracturing including hypocenter determination, moment and stress tensor inversion:
This research approach uses fundamental seismological methods in studying seismicity related to hydraulic fracturing operations. The well-defined methods in hypocenter determination of earthquakes (Kissling et al., 1994; Waldhauser and Ellsworth, 2000), moment tensor inversion (Jost and Herrmann, 1989; Cesca et al., 2013), and inverting the focal mechanisms to obtain stress orientations (Lund and Townend, 2007) make this approach relatively easier to implement. However, data from dense seismographic arrays are required for better constraining earthquake parameters as regional networks are usually sparse.

Coupled hydrogeology and geomechanical modeling of fault slip:
In this approach hydrogeological and geomechanical models are used to forward model the effect of injecting high volume of fluid into subsurface strata (Rutqvist et al., 2007; Keranen et al., 2014). These models aim to provide guidelines on how fluid injection changes the local stress regime at reservoir depths and on the adjacent fault planes that might be triggered as a result of injection. Several parameters must be known in advance including injection parameters (volume, pressure, and rate), regional orientation of principal stress components, and knowledge of the structural features in the area (fault planes with their dip and direction).

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SECTION 6. How Much Groundwater is Used for Hydraulic Fracturing?

6.1 Introduction

It is difficult to assess groundwater use in shale gas activities directly due to the current lack of a consistent system for data reporting. For instance, the Government of Alberta provides only surface versus groundwater allocation (rather than use), with such figures pertaining to the entire oil and gas industry and not specific to hydraulic fracturing (e.g. GOA, 2010); B.C. Oil and Gas Commission provides sub-basin-specific data on groundwater usage in hydraulic fracturing, but does not directly indicate whether the groundwater is fresh or saline (e.g. B.C. Oil and Gas Commission, 2012); and FracFocus.ca, though providing information for each well reported, provides only a single figure of volume use per well, without distinguishing between surface versus groundwater usage. The inconsistent and fragmented nature of available data makes it difficult to address questions about quantity and source of groundwater use in hydraulic fracturing. Moreover, it is often claimed that operators are increasingly moving from surface to groundwater sources and from fresh to saline groundwater (e.g. ALL Consulting, 2012; Rivard et al., 2014), but the lack of easily accessible, interpretable, and comparable data remains a significant information gap in supporting this claim. At present determining water the water sources for hydraulic fracturing is even more difficult than assessing overall water use in the process (Scanlon et al., 2014). Generally, without addressing these data problems, it will be challenging to form a comprehensive picture of the current impact of hydraulic fracturing on Canada's groundwater resources, or to estimate/predict impacts of future shale gas development.

In the CCA report, water use in hydraulic fracturing is addressed briefly and generally, noting that the water used is "primarily fresh water" (with no distinction made between fresh surface and fresh groundwater), that "[i]t can also come from deep saline aquifers," and that "brackish water is more likely to damage equipment and lead to formation damage" (CCA, 2014). The report provides averages for water use per well in six Canadian plays (figures cited from other sources; see Table 6.1), and its mention of groundwater specifically focuses on the potential contamination of groundwater from hydraulic fracturing. The lack of data regarding the source of water used in hydraulic fracturing is not noted in the list of water knowledge gaps.

Table 6.1. Average volume of water used per well in Canada (CCA, 2014).

Shale Gas Play	Average Volume of Water/Well (m^3)
Horn River Basin (BC)	76,900
Montney (BC)	6,700-9,700
Colorado (vertical wells in SK)	200-400
Utica (QC)	12,000-20,000
Frederick Brook (NB)	2,000-20,000
Horton Bluff (2 wells in NS)	5,900-6,800

6.2 Literature Review

The available literature on water use can be loosely divided into five groups: 1) scientific studies specific to Canadian plays; 2) review/overview studies; 3) government/regulator reports; 4) industry-provided information; and 5) studies on non-Canadian plays.

6.2.1 Canadian-Specific Scientific Studies

As shale gas is currently being exploited only in British Columbia and Alberta, most studies regarding hydraulic fracturing are focused on these regions (e.g. PRCL, 2010 and 2011 on the Horn River Basin; PRCL and CDL, 2011 on the Montney). However, these aquifer characterization studies aim to identify *potential* water sources, even in regions of active exploration, and so clear information on volumes and sources used in these regions cannot be gained from these studies. While newer studies have been undertaken in areas of exploration or early development, such as Central Mackenzie Valley in the Northwest Territories and the Liard Basin in northeast B.C. and the Yukon Territory (PRCL, 2012 and 2013), data on water volume use and sourcing cannot currently be extrapolated due to the nascent stages of the studies.

The only Canada-specific scientific study at the time of writing that clearly indicates total water volumes used by hydraulic fracturing (specifically in the Horn River Basin and the Montney Trend) is Johnson and Johnson (2012). This a detailed assessment of the water usage and gas production of 496 wells in northeast B.C. using multistage hydraulic fracturing, with a purpose of identifying the factors that most affect water consumption. Noting that previous predictions of water use trends have been based on reports from the Montney Trend and the Horn River Basin, Johnson and Johnson (2012) wanted to determine whether it is useful to extrapolate trends from one play to another, especially as the plays in northeast B.C. vary greatly in geology. After creating a new database from multiple sources, it was concluded that, despite variations in geology and fracturing technique, "water demand can be anticipated regionally through basin geology, treatment style for fracture stimulation and local trends in the numbers of completions per well" (Johnson and Johnson, 2012). This study shows that while using existing data sources to predict water consumption is challenging, it may be possible.

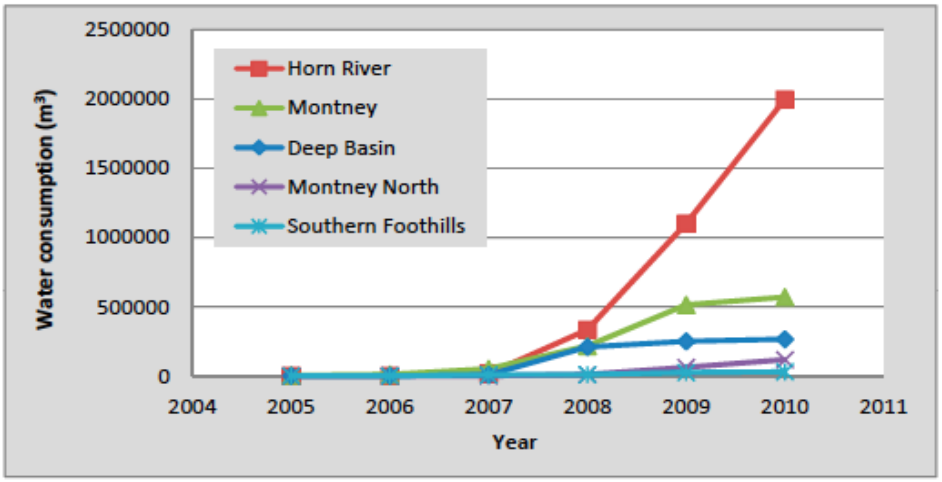

Figure 6.1. Cumulative water use by basin between 2005 and 2010 (Johnson and Johnson, 2012).

The source of water used in each play was not discussed in Johnson and Johnson (2012) or in Johnson (2012), nor was it mentioned as a factor that should be monitored, and so there is no way to separate surface water from groundwater usage in the provided figures. Johnson and Johnson (2012) further recommend the prioritization of research on saline water sources for high-volume use basins such as the Horn River Basin and Montney (note that PRCL, 2010 and 2011 are not cited).

6.2.2 Review/Overview Studies

With the beginning or proposed development of hydraulic fracturing in provinces and territories without a tradition of oil and gas production, as well as the increase in public interest in and awareness of the potential effects of hydraulic fracturing, several review and overview studies have come out in the last few years, often headed by committees looking to make decisions on how to best proceed with development (e.g. CCA, 2014). One such review occurred in the form of a two-day workshop in Calgary in 2011, focused on improving the geoscientific knowledge about groundwater management and protection in regards to hydraulic fracturing in Canada (Rivard et al., 2012). Water usage was among the topics discussed, and a wide range of figures for average total volumes of water use per well were reported (2,000-70,000 m^3 for B.C.; 5,900 m^3 and 6,800 m^3 for Nova Scotia's two previous wells; 200-400 m^3 for Saskatchewan, vertical wells; and 2,000-20,000 m^3 for New Brunswick). These figures indicate a wide variability of water use volumes due to the variable geology across Canada.

Precht and Dempster (2012) reviewed regulations regarding hydraulic fracturing in different jurisdictions to assist Nova Scotia in identifying current regulatory best practices. A questionnaire was administered followed by interviews with regulatory officials and technical experts in nine different jurisdictions at different stages of hydraulic fracturing development and regulatory maturity. Table 6.2 contains questions from the questionnaire pertaining to water use, with answers from Alberta, B.C., New Brunswick, and Saskatchewan (note that in many of the answers, it is difficult to separate out surface water use and regulations from groundwater use and regulations).

Table 6.2. Water use in Alberta, B.C., New Brunswick, and Saskatchewan (adapted from Precht and Dempster, 2012).

	Volumes of water used in hydraulic fracturing	What best practices are in place for water withdrawal practices?
Alberta	Slickwater fracturing ~50,000 m^3 per well.	Must investigate all reasonable alternatives, potential impact on other water users and impact on aquatic ecosystems. Subject to public notice. NOTE: Saline water (>4000ppm) is exempt from Water Act approvals.
British Columbia	10,000-25,000 m^3 per well in Montney Play; 25,000-75,000 m^3 per well in Horn River Basin.	Results based regulation, does not specify method of water withdrawal. Methods commonly used: pump water from a surface water source into temporary surface lines; surface water is pumped into a water truck then transported to destination.
New Brunswick	Ranges between 400 m^3 and 4,000 m^3 of water per stage; number of stages depends on geology, up to 4.	Surface water is preferred source, including run-off impoundments. Water for hydraulic fracturing often purchased from municipal sources. Wetland and Watercourse Alteration Program requires permit and fee for alterations, structures, and pipelines to withdraw water.
Saskatchewan	Volumes ~2,800 m^3 for tight formations.	(not answered)

Another overview study describes the status of shale gas exploration and production in Canada, including the geological contexts of each basin, water use, types of hydraulic fracturing, public concerns, and recent/current research efforts (Rivard et al., 2014). In the brief section on water use, it is stated that "[i]t is difficult to estimate how much water will be required for each well until test sites have been studied" (Rivard et al., 2014). The ranges/averages of volume of water used in B.C. as published in Johnson and Johnson (2012) and Precht and Dempster (2012) are cited. Water sourcing for B.C. and the Prairies was noted as being problematic, and data such as the base of fresh groundwater aquifers are said to be poorly known. However, the study points out that there are regional hydrogeological characterization studies in Quebec, Alberta, Saskatchewan, and B.C. to address these issues, as well as the Groundwater Program of the Geological Survey of Canada, expected to characterize thirty aquifers by 2024. The authors state that "[i]nitially, the industry preferred to use fresh water, but now companies can use brackish or even saline water" (Rivard et al., 2014), but no citation is provided for this information, nor is an explanation of what "can use" means in actual practice. Likewise, the conclusion that "the industry is evolving towards increasingly environmentally-conscious practices (e.g. use of saline water…, groundwater monitoring…)" (Rivard et al., 2014) is not supported, unless the academic/governmental research projects discussed indirectly show this.

6.2.3 Government/Regulator Reports

Under the current *Water Act,* the B.C. Oil and Gas Commission has the regulatory responsibility for Section 8 water approvals and use, which consists of surface water and short-term periods only (maximum one year), as well as the recent authority to issue long-term water licenses for the oil and gas sector. It also has authority over subsurface water access through the *Petroleum and Natural Gas Act.* Information included in the B.C. Oil and Gas Commission's Water Use for Oil and Gas annual reports has evolved as shale gas development has increased. For instance, the 2012 report was the first to include data regarding water use in hydraulic fracturing specifically, although it lacked figures on approvals for subsurface water access. Following this, the 2013 annual report was the first to provide data on fresh and saline groundwater use for hydraulic fracturing.

Table 6.3. Water used for hydraulic fracturing in B.C., 2012 and 2013 (B.C. Oil and Gas Commission, 2013).

	2012			2013		
PLAY	NUMBER OF WELLS	MEAN (m^3/WELL)	TOTAL WATER USE (m^3)	NUMBER OF WELLS	MEAN (m^3/WELL)	TOTAL WATER USE (m^3)
HORN RIVER BASIN	50	76,923	3,846,142	18	79,069	1,423,242
MONTNEY - HERITAGE	205	6,684	1,370,235	206	8,356	1,721,239
MONTNEY - NORTH	136	10,053	1,367,177	197	10,907	2,148,703
LIARD BASIN	1	144	144	1	20,106	20,106
CORDOVA EMBAYMENT	15	36,739	551,080	0		0
OTHER	12	221	2,651	11	2,577	28,345
TOTAL	**419**	**17,034**	**7,137,429**	**433**	**12,336**	**5,341,635**

The total volume of water injected for hydraulic fracturing in B.C. in 2013 was 5,341,635 m^3, over 433 wells, with the majority of those wells in the Montney Play (see Table 6.3 above). It can be extrapolated from the report's separation of volume of water extracted from water source wells from volume of water used under Section 8 approvals and water licenses that 683,528 m^3 (across 31 water source wells) of that total is definitely groundwater. A chart on the sources for acquisition of hydraulic fracturing water also specifies the percentage of fresh versus saline water source wells, with 7% being fresh and 0.8% being saline (see Figure 6.2; B.C. Oil and Gas Commission, 2013). However, to get specific data about which wells and operators use surface versus groundwater and fresh versus saline groundwater, a large number of different data sources have to be consulted and compared. Therefore, to draw any clear conclusions beyond the big picture, extensive data compilation and analysis are still needed.

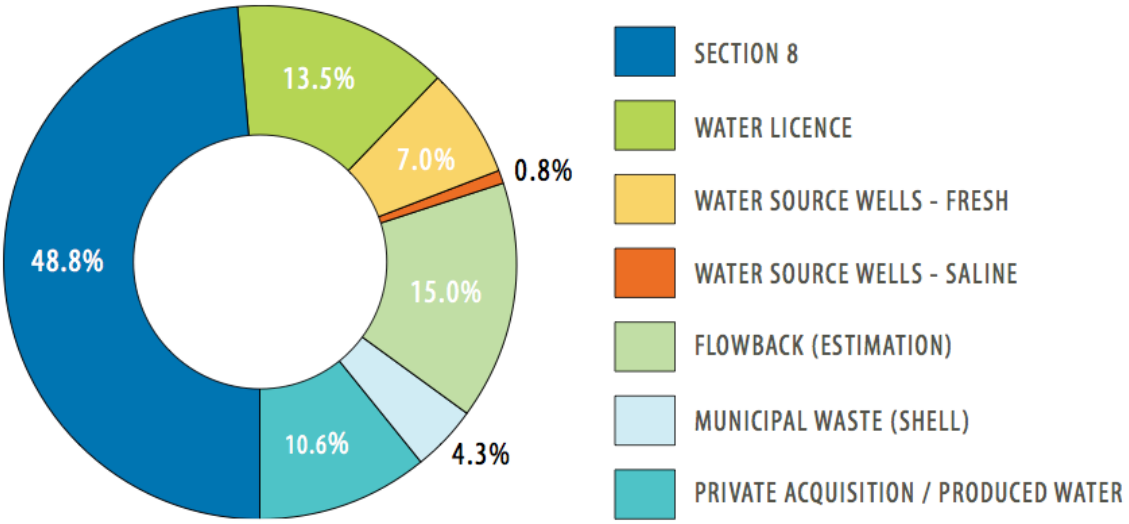

Figure 6.2. Sources for acquisition of water used for hydraulic fracturing in B.C., 2013 (B.C. Oil and Gas Commission, 2013).

The Alberta provincial government provides information regarding its groundwater resources on their website, such as the online 2010 report *Facts About Water in Alberta* (GOA, 2010)) and the Alberta Environment and Sustainable Resource Development (ESRD) State of the Environment reporting system. The GOA report (based on data from 2009) states that while Alberta has more groundwater than surface water, only 0.01% "is thought to be recoverable" (GOA, 2010); 26% of all water licenses issued in AB are for groundwater; and 3% of the volume of water licensed is groundwater. Unfortunately, in the groundwater use maps of Lemay and Guha (2009), use for hydraulic fracturing is not specified but probably included in 'industrial purposes'. Similarly, in the 2010 provincial report, the allocation of groundwater for the oil and gas industry is noted as a single figure (22.4%; the largest allocation).

It should be noted that the Alberta Energy Regulator (AER) has reported water use for in situ schemes since January 2012 (AER, 2015a). However, while AER states that licensees must report amounts and sources of water used (see AER, 2015b), no data has yet been provided on their website for water use in hydraulic fracturing other than a link to FracFocus.ca, which includes only total volume of water used, not source. Furthermore, CAPP's guidelines on water sourcing are voluntary, and AESRD's 2006 *Water Conservation and Allocation Policy* currently applies only to conventional oil and bitumen extraction (expected to be updated within the next couple of years).

On July 2, 2014, AER announced their Play-Based Regulation (PBR) pilot project in the Duvernay region, which will be guided by the Energy Resources Conservation Board (ERCB)'s 2012 Regulating Unconventional Oil and Gas in Alberta: A Discussion Paper, and the feedback gained from that paper. To address the issue of the large volumes of water used in hydraulic fracturing, ERCB advocates for the sustainable use of non-saline water, the increased use of saline water, and the understanding of the quantity of both surface and groundwater available for use. They also advise that operators include the

following in their play development plans: water sourcing options and assessments; what is known regarding the water inventory, existing use, and ecosystem needs; what the data gaps are; proposed water management systems for water access, transport, storage, use, and disposal; opportunities to reduce water use (specifically non-saline); the source and volume of water used at each stage; and an annual report of water use (ERCB, 2012). The last two points suggested for an operator's play development plan (source and volume used at each stage and report of water use) are particularly important to determining how much groundwater is used for hydraulic fracturing in Alberta.

6.2.4 Industry-Provided Information

Some of the most useful information regarding water use in hydraulic fracturing is likely to be gained from industry, particularly as larger companies make available general figures of water use on their websites for transparency and public interest. For example, Encana and Apache's use of Debolt Formation saline water pre-dates the studies of PCRL 2010 and 2011, with their joint project on the Debolt Water Treatment plant having opened in June 2010. Encana states on their website that 90% (or more) of the water used in their Two Island Lake operations (in the Horn River Basin) is from the Debolt plant; Apache (2012) states that more than 95% of Apache's and Encana's Horn River Basin hydraulic fracturing operations are supplied by the plant; and King (2012) states that the use of fresh water in the Horn River Basin by both Encana and Apache is negligible, with nearly 350 fractures completed with saline water in 2011. The fresh/saline groundwater proportion of the total volumes used per well by Encana in the Horn River Basin and elsewhere is not publicly available, as they only provide general company-wide ranges per well on their website, and total fresh/saline water use overall in 2012 and 2013 for their hydraulic fracturing operations (see Table 6.4; Encana, 2014). However, Encana notes that "[m]uch of the water used in hydraulic fracturing currently comes from fresh surface water sources" (Encana, 2014).

Table 6.4. Encana water use for 2012 and 2013 for hydraulic fracturing (adapted from Encana, 2014).

Water use (m^3)	2012	2013
Total fresh water (surface & groundwater)	5,457,312	6,657,617
Total saline water (groundwater)	8,334	11996
Total source water used (i.e. fresh and saline water sources)	5,465,646	6,669,082

Apache also only provides general information regarding its annual overall water use in Canada; in 2012 they used 14,004,000 m^3 non-potable groundwater versus 419,000 m^3 potable groundwater and 109,000 m^3 potable surface water, suggesting that their use of saline groundwater in the Horn River Basin is not a company exception (Apache, 2013). For example, King (2012), Apache's engineering advisor, states that the Apache 34L pad in the Horn River Basin, which has 12 wells and 154 fractures, uses brine rather than fresh surface water from "a salt water-containing formation located about 2,000 ft (610m) above the Horn River shale formations," in a closed-loop system (King, 2012). Furthermore, a

recent Apache annual sustainability report states that they source water for hydraulic fracturing in the Consort field in southeast Alberta from filtering wastewater from the nearby village of Consort (Apache, 2013).

A comprehensive look at all the current or at least top operators in Canada would be necessary to gain more data on water use. Aside from a brief mention of particular operators attempting to change their water use in Romanowska (2013), there is a lack of data collected directly from operators in the literature reviewed during this study, and a pointed avoidance of exploiting such a source of data. However, obtaining this information is crucial, as AER currently only refers to FracFocus.ca for such data, and the B.C. Oil and Gas Commission may not have data regarding groundwater use until groundwater is regulated under the new *Water Sustainability Act*, which will likely come into effect in 2016.

6.2.5 Studies on Non-Canadian Plays

Studies on specific U.S. plays could provide useful information for Canadian studies, such as Nicot et al. (2014), which looks to quantify the source and volume of water used, reused, and disposed in the Barnett Shale. Data from 2000 to 2012 from commercial and state databases (e.g. the IHS database), river authorities, groundwater conservation districts, and operators were analyzed; as the reporting of water sources is also not required in the U.S., information regarding sources was taken from both hard and soft data (e.g. interviews). Even within the same company, practices were found to differ greatly and the sourcing of water was shown to be a very dynamic business, "suggesting that collected information can only be considered semiquantitative" (Nicot et al., 2014). That said, interviews revealed that the typical approach of operators in the area included three phases: "Water-supply wells initially tap local groundwater unless the stimulated well is close to surface water. Then, after the initial period during which operators drill to hold leases (often 3 years) and explore for sweet spots…exploration and production become more predictable, and semipermanent water lines are installed from surface water reservoirs that can provide large amounts of water at relatively low cost. The third phase (from 2011) shows a renewed reliance on groundwater related to development of the combo play in Montague and Cooke counties" (Nicot et al., 2014). It was found that the periodic droughts of Texas "do not seem to control HF water use in the Barnett play, which is more sensitive to the price of gas and economic activity" (Nicot et al., 2014). As interviews indicated that only an estimated 3% of water used came from brackish aquifers, it can be assumed that most of groundwater used is fresh. Though this is a case study, the historical perspective and climate somewhat similar to southern Alberta allows the results of this study to be extrapolated for our purposes. As the authors say, "[u]nderstanding the source of the water used for HF is important to assess the impact on water resources" (Nicot et al., 2014). Further studies such as the Nicot study in the Barnett Shale should be conducted in other regions, particularly as the factors controlling water use practices in regions vary considerably.

Clark et al. (2013) noted that the quantity of water used had received little attention in previous literature, and investigated the amount of water consumed over the entire lifecycle of shale versus conventional gas production and water consumption of shale versus other fuels when used as a transportation fuel and in electricity generation. The study focuses on the Marcellus, Haynesville, Fayetteville, and Barnett plays in the U.S., and estimates the amount of water used for different

parameters involved in production, such as water used in drilling, cement, and hydraulic fracturing. Using data from 2011-2012 as available on FracFocus.org, an estimated volume of water used specifically for hydraulic fracturing was provided for each of the four plays (Barnett - 6,800-23,500 m^3/job; Fayetteville - 1,400-25,400 m^3/job; Haynesville - 12,900-33,400 m^3/job; Marcellus - 9,900-22,000 m^3/job). It was concluded that the production of shale gas consumes more water than the production of conventional natural gas, largely due to the vast amounts of water needed for hydraulic fracturing, and that the amount of water consumed in hydraulic fracturing varies greatly between plays. The study also recognized that although it did not address the potential impact of hydraulic fracturing on local watersheds, and "[a]lthough life cycle water consumption from shale gas development is less than other fuel production practices…it is possible that at the watershed scale, temporal and location effects from shale gas development could be significant and require further study" (Clark et al., 2013). Unfortunately, while it was noted that the primary purpose of the study was to track freshwater, there was no indication of whether the source was fresh surface or fresh groundwater. Such a study which separates the water use at each stage may be useful to study the impact of hydraulic fracturing on groundwater in Canada.

6.3. Knowledge Gaps

A full understanding of how much groundwater is used for hydraulic fracturing is hindered largely by information gaps, where the information is either missing or difficult to compile and collate. Regulation has not kept pace with shale gas development, which has resulted in insufficient data reporting regarding the source of water used in hydraulic fracturing. Additionally, data that are available are often difficult to access and interpret, and several sources may be necessary to obtain the desired information, such as how much surface water vs. groundwater/saline vs. fresh water is used in a certain well, play, or region. The fragmented nature of available data requires large scale compilation and analysis in order to advance current understanding of groundwater use in hydraulic fracturing.

6.4 Current Research Approaches

For their region-specific study, Johnson and Johnson (2012) and Johnson (2012) created a new database of well information with data from the OGC IRIS database (including data from the 'comments' field), IHS AccuMap, and geoLOGIC Systems geoSCOUT program. Well and fracture data were analyzed using Excel, and spatial distribution and grouping was evaluated with ESRI ArcGIS. In the other (Canadian) literature reviewed above, the method of obtaining data on water use (if an effort is made to obtain such data) has been to repeat data from previous literature (including Johnson and Johnson, 2012), use publicly accessible general data (e.g. FracFocus.ca, government reports), conduct interviews with regulatory officials and technical experts (Precht and Dempster, 2012), or, based on the lack of citations, use personal knowledge. None of the (Canadian) literature seemed to collect detailed data directly from regulators or operators.

6.5 Range of Research Approaches

Table 6.5. Range of practical research approaches to address knowledge gaps.

	Research Approach 1: Comprehensive study of existing oil and gas and provincial databases to constrain historical water usage in hydraulic fracturing	**Research Approach 2: Reporting of the complete water budget in hydraulic fracturing, including sourcing, recycling/reuse, and disposal**	**Research Approach 3: Study *where* water comes from in various plays, to inform future water use practices**
Complexity	Moderate; requires cross-referencing multiple databases	Low; tabulation of water use across the hydraulic fracturing process	Moderate; must identify current and potential water sources, and issues around their use
Risk/Uncertainty	Moderate; information in databases can be incomplete or unclear	Low; assuming standard reporting methods, should be straightforward	Moderate; current practices can only help to inform future use plans
Timeframe	Low; 1 - 3 years for a region	Moderate; requires policymakers to consult with stakeholders	Moderate; requires researchers to consult with industry and government
Cost	Moderate; purchased access to oil and gas databases, personnel; $100K's	High; significant cost to industry to implement more precise water budgets	Moderate; significant time, personnel to collect data from multiple sources
Research Capacity	High; a number of people skilled in the use of the databases exist	High; low expertise required to collect, tabulate data	High; requires a team to collect and interpret existing data
Difficulty of Implementation	Low; data tabulation in office and skilled personnel needed	Moderate; increased standards of reporting could be cumbersome to industry	Moderate; combines information from regulators and collaboration with industry
Socio-Political Concerns	Data sets likely incomplete / lack resolution, public may desire a more proactive approach	A complete water cycle budget would likely be looked upon positively by the public	Determining water current patterns use likely to receive public support
Likely Achievements	Play-level sense of water use, and identification of knowledge gaps leading to better policy	Precise numbers, both over time and geographically, of water use volumes	An understanding water resources in differing plays that will inform future use practices

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SECTION 7: What is the Impact of Hydraulic Fracturing on the Groundwater Component of the Water Budget?

7.1 Introduction

The previous section addressed knowledge gaps related to how much groundwater is used in hydraulic fracturing; this section will focus on the impact of this use on the total water budget. Most attention given to groundwater and hydraulic fracturing is in terms of quality, not quantity (e.g. Jackson et al., 2013). Further, it is generally believed that saline aquifers are not of great use for non-industrial purposes, and so little attention has been given to the increased number of recommendations for hydraulic fracturing to use as much non-freshwater groundwater as possible (e.g. Johnson and Johnson, 2012; Rivard et al., 2012; ERCB, 2012). With communities in the U.S. that are experiencing water scarcity already turning to treating saline groundwater for drinking water (Freyman, 2014a), and the so-far unpredictable future of Canada's water resources in the face of climate change, the notion of saline groundwater being a potential long-term source for Canada's plays warrants a second thought. Furthermore, recent studies on both the national and global increase in use of groundwater (e.g. Rivera et al., 2003; Giordano, 2009) give merit to the integration of general groundwater studies with studies on hydraulic fracturing and water. In order to develop a comprehensive and sustainable water management plan, both surface and groundwater resources must be accounted for, as well as current and planned use of such resources by the growing hydraulic fracturing operations (e.g. CCA, 2009, on the sustainable management of groundwater in Canada, does not address the current or potential effects of hydraulic fracturing).

7.2 Literature Review

Literature directly related to the impact of hydraulic fracturing on the groundwater component of the water budget in Canada was not found during this study. The most relevant sources then are those that indirectly address the issue (e.g. by indicating potential future water quantity problems or by discussing/critiquing current groundwater management practices), or discuss the issue in a non-Canadian context. The literature reviewed can be loosely divided into four groups: 1) national reports, 2) review/overview studies (all of which were discussed in the previous section on water use), 3) reports on groundwater management, and 4) studies on non-Canadian plays.

7.2.1 National Reports

The CCA report's mention of groundwater focuses on the possible contamination of groundwater; the use of groundwater is addressed very briefly, and the use of either surface or groundwater is not discussed in terms of how it might impact the groundwater component of the water budget. The report concludes that though "water use may be an occasional problem…[it] can be avoided by good water management practices," and notes that "the absolute volumes withdrawn are often less important than the times and rates at which water is taken" (CCA, 2014).

The UK report (The Royal Society and The Royal Academy of Engineering, 2012) only indirectly touches on the impact of hydraulic fracturing to groundwater resources, in that it notes that there are concerns about depletion of local water resources from hydraulic fracturing and that there is a requirement for

operators to get an abstraction permit for surface or groundwater extraction over a certain limit (20 m^3). Therefore, while there is a notion of the rate of withdrawal being important to avoid short-term water shortages, there is no direct comment on how water use impacts the groundwater component of the water table.

In contrast, the Australia report addresses the use and management of groundwater extensively, due to the fact that hydraulic fracturing operations there would likely use groundwater as their primary source, as well as the fact that natural recharge rates of groundwater in Australia are generally low, particularly in regions with shale gas (ACOLA, 2013). This is one of the only reports addressing hydraulic fracturing and water that recognizes that surface water and groundwater are connected in terms of quantity as well as quality, rightly noting that "[t]he traditional separation of surface and groundwater can be convenient, but often fails to recognize that surface and groundwater are components of the same hydrological system" (ACOLA, 2013). The report recommends that use of *both* surface and groundwater must be minimized, and notes that avoiding over-extraction of potable water from aquifers and avoiding aquifer interference and perturbation of groundwater flow are two main components of water management for shale gas production. The report also notes that the use of deep saline aquifers for water should require a regulated management plan, not only to avoid excessively impacting groundwater pressure, but also because the high TDS water is used for watering livestock in the region (ACOLA, 2013). The attention the report devotes to the impact of hydraulic fracturing on the groundwater component of the water budget is absent in Canadian studies, likely due to the greater abundance of water in Canada. Nevertheless this issue should be similarly considered in future Canadian studies.

7.2.2 Review/Overview Studies

Rivard et al. (2012) note that, "in some areas, even if water quantity may not be an important issue now, it could become one, with the increasing number of wells and the number of fracking processes per well." While this issue was not discussed further, other conclusions reached did, however, include the following: research studies must be developed to reduce fresh water and overall water consumption in slickwater fracturing; the use of saline/brackish water must be fostered; baseline characterization must be carried out prior to exploration; collaboration between provinces as well as between countries with more data is necessary; and data must be made available and accessible (particularly in a consolidated database), including maps of shale formation targets superimposed on maps of known aquifers, and the source of water used (as it was noted that only total volume of water use is currently required in reporting, not the source of water) (Rivard et al., 2012).

The questionnaire and interview results discussed in Precht and Dempster (2012) indicate that there is not a direct recognition of the potential impact on the groundwater portion of the water budget by hydraulic fracturing by the four provinces that participated in the study (Alberta, B.C., New Brunswick, and Saskatchewan). It was noted that the primary concern surrounding the practice of hydraulic fracturing is water, and so the focus of many hydraulic fracturing regulations is the protection of water quality and sources of water. In particular, seven key issues regarding hydraulic fracturing were identified, one of which was water allocation. Regulations relating to the impacts of using groundwater

continue to develop (Table 7.1). For example, the B.C. Oil and Gas Commission (BCOGC) has a trigger groundwater withdrawal rate, New Brunswick states that the rate of withdrawal must be sustainable, and Alberta's *Guide to Groundwater Authorization* (2011) places limits on the quantity of groundwater use and how use is to be evaluated. B.C. will be updating their water licensing practices ~2016 (with the *Water Sustainability Act* replacing the current *Water Act*, to regulate groundwater) and the new Alberta Energy Regulator (AER) has regulatory functions relating to water use in the oil and gas industry which may become clearer after their just-launched Play-Based Regulation pilot project (c.f. Section 6).

Rivard et al. (2014) conclude that studies "should provide an impartial scientific base to support the sustainable use of groundwater related to shale gas development" (Rivard et al., 2014). Use of the word 'sustainable' indirectly indicates that hydraulic fracturing may have an impact on the groundwater portion of the water budget; however, a conclusion that research projects will result in the sustainable use of groundwater is only an assumption (if not only a desired result). The authors do not comment on the impact of hydraulic fracturing on groundwater in U.S. plays. While this is understandable for a study exclusively on Canadian plays, shale gas production in Canada is much younger than that in the U.S. and it is logical to see our future in their present unless significant changes are considered; thus some consideration of how water use practices have evolved in the U.S. over the past decade of large-scale shale gas development would be helpful to Canadian researchers.

Table 7.1. Regulatory processes regarding water use in Alberta, B.C., New Brunswick, and Saskatchewan (adapted from Precht and Dempster, 2012).

	Bodies responsible for regulating water resource usage for unconventional resource development	Trigger for water withdrawals (does water withdrawal over a certain amount trigger regulatory requirements?	Are potential impacts on other users of the water considered?	What are important environmental issues related to hydraulic fracturing operations in your jurisdiction and how are you addressing these issues?
AB	Alberta Environment and Water (AE&W) regulates water resource usage for all oil and gas activities. NOTE: Alberta government has now integrated the ERCB and relevant portions of AE&W and SRD (Sustainable Resource Development) into a single oil and gas regulatory agency, the Alberta Energy Regulator (AER).	AE&W under the Water Ministerial Regulations distinguishes between temporary and permanent water permit. 5000 m^3 triggers the requirement for a water diversion approval on Crown lands. All other lands, any freshwater (TDS <4000 mg/litre) use requires water diversion approval.	Yes. Restrictions on withdrawal may be imposed based on senior water rights holders.	Water, including sourcing and protection. Cumulative effects, including footprint management and mitigation. Noise.
BC	The B.C. Oil and Gas Commission can authorize short-term (i.e. ≤12 months) surface and subsurface water use for oil and gas activities, whereas the Ministry of Forests, Lands and Natural Resource Operations is responsible for long-term water surface water licenses.	Groundwater withdrawal rates exceeding 75 L/s requires an Environmental Assessment under the Environmental Assessment Act (no distinction between saline and non-saline water).	Domestic users have priority over industrial/commercial users in situations where withdrawals may be impacted by drought etc.	Surface and ground water use/protection. Introduced quarterly water reporting, on-line posting of short term water approvals. Basin management of unconventional resources, looking at large scale water withdrawals
NB	(did not specify which of the following regulates water use) Department of Natural Resources, Department of Environment, Department of Transportation – trucking, WorkSafe NB	>50 m^3/day (capacity, not use) triggers a phased EIA process. Need to test sustainability of withdrawal and impacts on adjacent users. Intake 30 m from a watercourse or wetland trigger for EIA. No water withdrawal permits or fees currently in place.	Water access is “first come, first served”. This hierarchy of water use is in NB’s Environment Protection Plan, Water Strategy will be released. NOTE: Important to establish rate of withdrawal is sustainable.	NB Environment involved in assessment, use tools such as Groundwater Chemical Atlas.

SK	SK Watershed Authority responsible for surface water and ground water, including: approving and licensing water use projects for industrial purposes, and construction and operation of water works. Dept of Environment regulates through an EIA process. Development projects are screened, especially in sensitive and undeveloped areas.	Any surface water use requires a water rights license from SK Watershed Authority (SWA). Data obtained in ground water investigation program may be submitted in a final engineering report within 60 days of conclusion of the program. Any plans, information, or data filed respecting ground water use with Dept of Energy and Resources available to SWA.	Oil and gas industry accounts for 1% of industrial water use. Oil and gas industry uses mostly surface water.	Pollution of groundwater aquifers, and the use of large quantities of water. SK requirements ensure hydraulic fracturing does not take place in close proximity to potable groundwater.

7.2.3 Reports on Groundwater Management

With increasing global concern on protecting groundwater, literature on the general human impact on groundwater and proposed management plans can be found. Giordano (2009) discusses that the sudden increase in groundwater use has not been met with updated management practices, resulting in questionable sustainability on both a global and regional scale. While globally there does not seem to be a groundwater problem, he notes that "[t]he size of storage and slow rate of flow mean that it may take a generation or more of overabstraction before it is clear that a problem is present." Management frameworks must be set in place to provide solutions to potential groundwater issues, with the most effective likely being "policies based on a broad view of resource systems and human adaption" (Giordano, 2009). Furthermore, Giordano (2009) states that "deficiencies in [local/regional/global] data and information on groundwater availability and use as well as the physical and social impact of that use" should be addressed.

Addressing the issues specific to groundwater management in Canada are rather difficult. For the most part, water resources in Canada are not federally regulated, but are under the jurisdiction of the province/territory in which they lie. Even when the federal government does have direct responsibility regarding water, federal water legislation has not been updated since the 1970s, and thus it is likely that regulations are outdated for the current status of Canada's groundwater resources. As a result, there are often large governance gaps and challenges, such as lack of inter-governmental coordination, poor data collection and sharing, and inadequate monitoring and enforcement. Furthermore, many issues with water resources specifically increase the number of difficulties, as water bodies (surface and ground) may cross provincial/territorial boundaries and environmental governance may conflict with resource development, "which is a major source of income for provinces as well as a main means by which they assert their autonomy" (Bakker and Cook, 2011). As hydraulic fracturing operations are either fairly new or non-existent in the majority of the provinces/territories, modifications to existing groundwater use regulations for hydraulic fracturing operators continue to be discussed.

These reasons may explain why the majority of studies and reports on water management in Canada do not address groundwater use in hydraulic fracturing. However, as some regions of Canada have experienced groundwater quantity issues, and as alternatives to surface water are increasingly being recommended for hydraulic fracturing operators, it is important to address the two topics of groundwater management and groundwater use in hydraulic fracturing together. The purpose of the *Canadian Framework for Collaboration on Groundwater* (Rivera et al., 2003), for example, was to suggest the mechanisms needed to acquire the information necessary (e.g. a national groundwater inventory and regional monitoring programs) to manage and protect Canada's groundwater, and to provide policy makers access to that information in order to establish adequate guidelines for long-term management. With co-ordination and collaboration between provincial governments, the federal government, and stakeholders being noted as key to the successful managing of Canada's groundwater resources, establishing a Canadian Groundwater Advisory Council and a Federal-Provincial Groundwater Committee were suggested as the initial step. The next steps would then be funding/undertaking/identifying/promoting national co-operative programs; initiating/promoting communication; and developing/providing/promoting performance standards and uniformity across

Canada. The report also noted that regions throughout Canada are experiencing groundwater quantity issues "due to increasing demand, contamination…and potential variations in recharge patterns due to climate-change impacts" (Rivera et al., 2003) and quantity problems specific to each province/territory are noted in Appendix 1 of the report. Such information (i.e. that groundwater quantity is an issue in some regions and will likely become a larger issue in Canada's future) is rarely mentioned in studies on groundwater use in hydraulic fracturing, and so this acknowledgement is sorely needed. That said, there is absolutely no mention in the report of water use in hydraulic fracturing, and so its list of issues requiring additional research is not entirely comprehensive.

More current reports than Rivera et al. (2003), such as the CCA report on the sustainable management of groundwater in Canada (CCA, 2009), also do not address the current or potential effects of hydraulic fracturing on sustainable groundwater management practices. This report, based on knowledge from the expert panel, case studies, and input from stakeholders (collected from a public call for evidence), concludes that there is no immediate widespread groundwater crisis in Canada, but that Canada needs to take a proactive stance and learn from countries who have experienced over-exploitation and contamination of groundwater. It is noted that there is a critical lack of data needed for effective management. In particular, records of the amount of water actually withdrawn by licensed users are generally not available, and are needed to calculate projected consumption; as of 2009, only Alberta and Saskatchewan record the amount taken (with Ontario and Manitoba planning to move to this system), and Quebec and B.C. do not have databases of allocations at all (CCA, 2009). Furthermore, as current water-related policies and regulations as well as hydrogeological research either focuses on groundwater quality alone or separates quality issues from quantity issues, the report recommends that policies/regulations and studies dealing with both aspects should be developed for more comprehensive management and knowledge. The closest that the CCA report gets to addressing the impact of groundwater use in hydraulic fracturing is in stating that "burgeoning energy production" is one of the main threats to groundwater (CCA, 2009). This statement comes out of a brief discussion on oil sands and coalbed methane, as well as a case study on the Athabasca oil sands and groundwater use in its in situ production methods (particularly the SAGD technique); the term 'hydraulic fracturing' does not occur in the entire report. Future groundwater reports similar to CCA (2009) should recognize hydraulic fracturing as a popular method of energy production separate from in situ methods, and one that uses a growing amount of Canada's groundwater resources.

7.2.4 Studies on Non-Canadian Plays

A trend found in the literature reviewed above is the repeated identification of the need for focused studies on the impacts hydraulic fracturing has on Canada's groundwater resources. While this may suggest that little work is actually being done on the topic, there are a number of general and focused studies in other countries that can provide information and be extrapolated to our own situation. As discussed above, ACOLA (2013) provides the most extensive discussion thus far on the impact of hydraulic fracturing to the groundwater component of Australia's water budget, providing many relevant points of discussion for future Canadian studies. The U.S. Environmental Protection Agency (EPA) is currently conducting extensive research on hydraulic fracturing's potential impact on drinking water resources through eighteen projects and five different types of research activities (analysis of

existing data, scenario evaluations, laboratory studies, toxicity assessments, and case studies) (EPA, 2012). The scope of the research is designed around the five stages of the hydraulic fracturing water cycle, and one of the five primary research questions focuses on water acquisition, specifically the possible impacts of large volume surface and groundwater withdrawals on drinking water resources. The secondary research questions surrounding the water acquisition stage are: how much water is used in hydraulic fracturing operations, and what are the sources of this water; how might water withdrawals affect short- and long-term water availability in an area with hydraulic fracturing; and what are the possible impacts of water withdrawals for hydraulic fracturing on local water quality.

Even a general U.S.-focused literature review like Vengosh et al. (2014) provides valuable information for Canadian plays. This survey of literature (up to January 2014) summarizes the risks to water resources from hydraulic fracturing and solutions that have thus far been identified. Four risks were identified: stray gas contamination of shallow aquifers; contamination of surface and shallow groundwater from spills, leaks/disposal; accumulation of toxic elements near disposal/spill sites; and over-extraction of water resources that could induce water shortages/conflicts. In terms of the last risk, the study cites the conclusions of Freyman and Salmon (2013) (discussed below), stating that "in geographic areas with drier climates and/or higher aquifer consumption…groundwater exploitation for hydraulic fracturing can lead to local water shortages" (Vengosh et al., 2014). The authors further state that such shortages can lead to "subsequent degradation of water quality" (Vengosh et al., 2014). The study suggests that alternative water sources be used, and indicates the need for studies on other basins, as the majority of the literature available focuses on the Appalachian Basin.

Lastly, one important set of (mainly) U.S.-based studies not necessarily on water withdrawal impacts but on the correlation of areas experiencing water stress and hydraulic fracturing operations comes from the Water Program at Ceres, particularly Freyman (2014a). This is one of the few reports to focus solely on Stage 1 of the water lifecycle in hydraulic fracturing (water use and its impacts), and it is the most recent. As opposed to the CCA report (2014), which relies primarily on peer-reviewed scholarship, it includes industry information as well as more non-scholarly sources such as opinion and news articles to offer a more comprehensive view of the issues at hand. As such, it is geared towards providing information regarding the potential and present water stress challenges for those directly involved in hydraulic fracturing operations, acknowledging that the reputation of and public support for any particular operator is a major issue for the industry. The study provides a necessary analysis of the water volume and other well data available on FracFocus.org (from 39,284 U.S. wells) and the World Resource Institute (WRI)'s *Aqueduct Water Risk Atlas* to calculate the correlation of water use to areas experiencing water stress, drought, and groundwater depletion, focusing particularly via case studies on eight regions (the Eagle Ford Play, Permian Basin, Monterey, Bakken, the Marcellus, Denver-Julesburg Basin, Alberta, and B.C.). It was found that "[n]early half of the wells hydraulically fractured since 2011 were in regions with high or extremely high water stress, and over 55 percent were in areas experiencing drought", with "extremely high water stress" defined as meaning that over 80% of the available water (surface and groundwater) is already allocated (Freyman, 2014a). Also, over 36% of the U.S. wells were found to be in regions experiencing groundwater depletion.

Unfortunately, very little analysis is provided in Freyman (2014a) for hydraulic fracturing in Canada specifically. This is largely due to there being much less data available on FracFocus.ca (data for only 1,341 Canadian wells was available at the time of study), "inconsistencies with the units [of water volume] reported" (Freyman, 2014a), and, as previously mentioned, the lack of reporting of groundwater withdrawals in B.C. The report does note however that, based on the available data, 20% of wells in Alberta are in areas of medium and higher water stress, with Encana and Canadian Natural Resources having the most number of wells in areas of high water stress.

Recognizing that the number of wells and thus water demand for hydraulic fracturing will only grow in the future, and that no single technology or water management practice will mitigate water sourcing problems, the report provides ten pages of recommendations to operators for disclosure and transparency (focused on disclosing water volumes, sourcing, and projected water needs), operational practices (focused on minimizing water use and recycling/reusing water), and stakeholder engagement. The gaps left by Freyman (2014a) are then to analyze the data on FracFocus.ca to see where the water use trends discussed for the U.S. regions could be extrapolated for Canada (in particular, perhaps, the work done by the Susquehanna River Basin Commission, which now has data for the full water lifecycle, and is in a state considered to be relative water-rich; Freyman, 2014a), assuming that the number of wells reporting/present in Canada could eventually increase to the same level of at least some of the regions discussed in the report. Freyman noted in her May 2014 presentation (Freyman, 2014b) that the World Resources Institute is planning on doing such as a study for Eastern Canada, looking at how the locations of resources compares to the locations of water stress. Additionally, data on the sources of water used are scarce, which are necessary to most effectively translate the conclusions of the report. Based on the data provided in the study pointing out which companies most often operate in areas of water stress, it would be interesting to know whether water use practices differ between large versus small companies; in her May 2014 presentation, Freyman noted that Ceres will be assessing companies' water management in an upcoming study (Freyman, 2014b). Lastly, the mention of the USGS's prediction that "brackish groundwater could in some areas supplement or even replace use of freshwater sources" and that "[m]any parched communities are already turning to brackish water resources for drinking water supplies due to declines in fresh groundwater resources" (Freyman, 2014a) should be investigated further for its relevance to Canada, and at least kept in mind when brackish groundwater is touted as an optimal water source for Canadian plays.

7.3 Knowledge Gaps

There is lack of studies that directly address the impact of hydraulic fracturing on the groundwater component of the water budget in Canada, reflecting a general sentiment that this issue is not a significant concern. However, to take a proactive stance and learn from countries that have experienced overexploitation of groundwater as the CCA report (2009) recommends, it is important to identify and fill knowledge gaps related to this topic now. A primary information gap is one that is addressed in Section 6 of this report: the lack of data or easily accessible data regarding water use and source in hydraulic fracturing. As the CCA report (2009) points out, there is a critical lack of data needed for effective groundwater management. A subsequent understanding gap exists in how best to combine this information (once acquired) with effective groundwater management in the context of growing

shale gas development. Additionally, it is important to improve understanding of groundwater impacts from hydraulic fracturing on a local scale, where effects may be more evident and potentially more problematic than on a regional scale.

7.4 Current Research Approaches

In the Canadian literature reviewed above, no research approaches for addressing the impact of hydraulic fracturing on the groundwater component of the water budget can be identified, as no Canadian study found addresses this issue.

7.5 Range of Research Approaches

Table 7.2. Range of practical research approaches to address knowledge gaps.

	Research Approach 1: Devise play-based groundwater monitoring programs in regions of BC and AB where groundwater is used for hydraulic fracturing	**Research Approach 2:** Construct numerical GW models to predict the impacts of pumping groundwater for use in hydraulic fracturing	**Research Approach 3:** Mandated GW use reporting to provincial gov't from industry and compilation into one database
Complexity	Moderate; uses existing monitoring technologies, but requires proper design	High; significant detail about hydrostratigraphy, scale of model needed	Low; collect data only, some interpretation desirable
Risk/Uncertainty	Moderate; groundwater systems are often complex and can be difficult to monitor	Moderate; although GW models have inherent uncertainty, they are a proven decision making tool	High; although the amount of GW would be known, the impact of removal is not considered
Timeframe	Moderate to high; field monitoring system requires years to develop	Moderate to long; 2 - 5 years, depending on scale of modelling	Moderate; depends on initiative of government
Cost	High; likely millions or more at the regional scale	Moderate to high; from high $100K's to low millions	Low; operators only required to report
Research Capacity	High; expertise exists in provincial, federal government and academia	High; expertise exists in federal government and academia	Moderate; catchment-scale data interpretation by specialists would be needed
Difficulty of Implementation	High; many resources required to implement	Moderate; skilled groundwater modelers and some field monitoring required	Moderate; requires consultation with stakeholders
Socio-Political Concerns	Low; public likely in favour of protecting resources, monitoring system would have other uses	Low; groundwater models are a proven policy tool	Moderate; public may view this action as 'too little' in terms of environmental protection
Likely Achievements	Monitoring of changes in water quantity and quality (chemistry) in shallow aquifers	Broad constraints on the impacts of pumping groundwater in modeled region	A solid handle on the amount of groundwater used, but limited insight into impacts

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SECTION 8: What is the Impact of Groundwater Use on Other Major Users and the Existing Water Market?

8.1 Introduction

The majority of the scientific literature to date has focused on water quality impacts of shale gas development, with less research on the water quantity impacts (see Mason et al., 2014 for a review). There is particularly little literature on whether increased water use by hydraulic fracturing is reducing water available to other diverted uses.

Water inputs to hydraulic fracturing vary with geology, the amount of recoverable gas, number and length of horizontal wellbores, and other factors (Veil, 2010; Nicot et al., 2014). Recently, data on the quantity and source of water used in hydraulic fracturing in Canada have started to become available. For instance, hydraulic fracturing water use data in British Columbia for both surface and groundwater since 2011 are available and reported both quarterly and annually from the B.C. Oil and Gas Commission. Although not free to the public and accessed only upon approval, the Canadian Discovery Well Completion and Frac Database (WCFD) is another data source that reports data on water use and type of water used (fresh or produced) by the hydraulically fracked wells in Alberta, British Columbia, Saskatchewan, and Manitoba (Canadian Discovery, 2015).

Water used in hydraulic fracturing could reduce the flow of rivers and streams, diminishing ecosystem services and water available for other diverted uses. Along many dimensions, the quantities of surface water used for shale gas development are small (Nicot and Scanlon 2012; Mitchell et al., 2013; Kuwayama et al., 2015). However, the risks associated with surface water consumption can be expected to vary over both time and space. Most of the water consumption in shale gas production occurs within one to five days during the hydraulic fracturing process and if this water was all diverted during a low-flow period (summers, droughts), there may be more significant ecosystem impacts (Entrekin et al., 2011). The regulation of water withdrawals and water rights structures will mitigate the impacts of withdrawals to varying degrees. Additional research on these spatially and temporally variable impacts is warranted.

If the physical impacts of water withdrawals for fracking were quantified, they could also be monetized. Estimating the value of instream water for recreational use or ecosystem maintenance often requires nonmarket methods such as recreational demand models, contingent valuation surveys, and hedonic housing models. Substantial literature using these methods now quantifies the marginal value of surface water left instream for recreation, riparian and wetlands restoration, and other purposes in many different parts of the world (Hansen & Hallam 1991; Loomis et al. 2000; Ojeda et al. 2008). Thus far, there are no estimates in the literature of the economic value of reducing risks of shale gas extraction related to surface water and groundwater scarcity.

A reasonable approach to valuing the marginal damages from groundwater or surface water depletion would be to consider the opportunity cost. For example, the marginal value of water inputs to lost agricultural production among uncompensated agriculture users of a common aquifer would be relevant in some regions (Hitaj et al., 2014). In others, the relevant marginal damages might be to urban users. Cutter (2007) estimates the marginal damage associated with reduced ability to withstand drought in groundwater-dependent urban areas; aquifer depletion in this study resulted from increased impervious surface due to urban land development, but the technique could be adapted to value the damages associated with competition from fracking for shared groundwater.

8.2 Literature Review

8.2.1 Groundwater Use

Because groundwater is not as evenly distributed as surface water across any province, aquifer depth, yield, and water quality vary from region to region. Groundwater allocation among users is different from surface water allocation. For example, typically the agricultural sector is the highest allocated user of surface water whereas the industrial (oil and gas) sector is usually the highest allocated user of groundwater (Figure 8.1). Although hydraulic fracturing operators claim that they have reduced the use of fresh surface/groundwater, it is difficult to verify this with the current data available. Thus, it is challenging to measure the impact of hydraulic fracturing water use on other users.

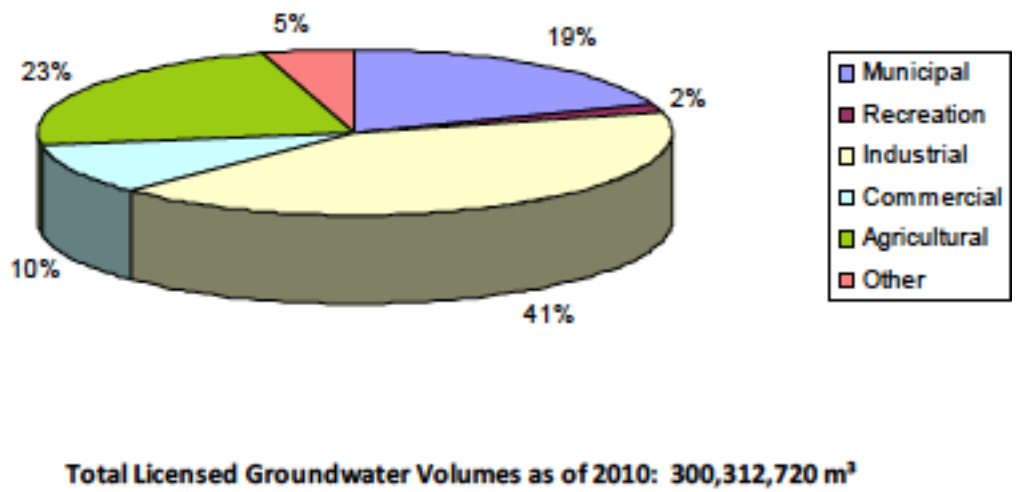


Figure 8.1: Groundwater allocation by use in Alberta in 2010. Source: Alberta Environment and Sustainable Resource Development.

8.2.2 Effect of Hydraulic Fracturing on Other Major Users and the Current Water Allocation System

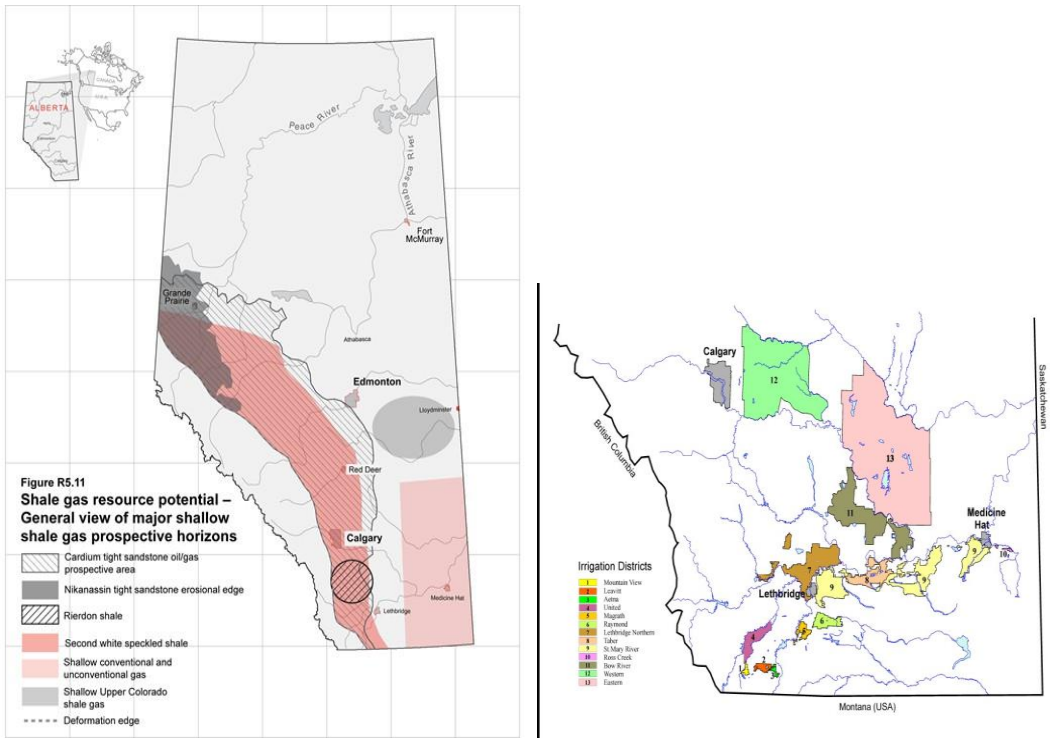
Water is a limited resource and is shared by various users over time. Besides the oil and gas sector, the agricultural sector (through irrigation water use) is the primary user of water. The effect of hydraulic

fracturing on the agricultural sector is important since both the unconventional oil and gas industry and the agricultural sector share this resource as an input. Water sharing among multiple sectors can result in water scarcity, which eventually can hinder their production process.

Gaudet et al. (2006) examine the optimal way for sharing a scarce input resource by the agricultural and oil sectors. Using a theoretical framework, their analysis shows that for sufficiently large oil stocks, it becomes optimal to have a phase during which the agricultural sector is inactive. This result also means there is a phase first during which the two sectors are active, then a phase during which the water is reserved for the oil sector and the agricultural sector is inactive, followed by a phase during which both sectors are active again. In the end, as the oil stock is depleted and the demand for water from the oil sector decreases, only the agricultural sector remains active. The interdependence between these two sectors, through sharing a common constraint, plays a major role in determining how much water these sectors will use. The result from this study is important since it can be used as a theoretical basis for an empirical study examining the effect of hydraulic fracturing on agriculture's water use for irrigation, of which there are no known studies to date.

8.2.3 Alberta as a Case Study

According to the *Alberta Water Act*, any person who needs to use water in excess of 1,250 m^3 per year is required to obtain a license for water use. Alberta Environment regulates this license distribution and water allocation among the license holders. Since August 2006, Alberta Environment stopped issuing new licenses for surface water allocation in the Bow River, Oldman River, and in the South Saskatchewan River basin and approved the law of temporary or permanent water transfer among the license holders. Based on this transferring system, a user can temporarily or permanently transfer partially/all of his or her water allocation to another user under certain conditions. All transfers are monitored and approved by Alberta Environment (Adamowicz et al, 2010). Therefore, upon approval of this water allocation transfer system, in case of surface water, a water market has emerged inside Alberta. However, Alberta Environment is still allocating water licenses to withdraw groundwater to date, where older licensees hold priority over newer/more recent license holders. These licenses can also vary by duration; for instance, there are temporary diversion licenses (maximum one year duration) and term licenses (five years duration; Alberta Environment).



(a) Shale gas in AB (b) Irrigation Districts AB

Figure 8.2. : Prospective shale gas plays and irrigation districts. Source: Alberta Energy Regulator (AER), Alberta Agriculture and Rural Development.

Figure 8.2 shows the location of the potential shale gas wells (panel a) and the location of the irrigation districts (panel b) in Alberta. Since these sectors are overlapping geographically and use a common input resource, water, there is a need to investigate the interplay among these sectors.

However, different sectors can have heterogeneous effects through their water usage as water withdrawal location and procedure could vary among sectors. In Holmes' (2012) discussion of the heterogeneous effects of different water users on the water market of Alberta, he notes that the effect of withdrawing water by various users varies with the spatial location of the water sources since the natural flow of the rivers differ with their locations; thus, different sections of a river system have heterogeneous needs for minimum sustainable flow. He further explains how a single user can affect other users when all of them are using the same water source. As water is a renewable resource and can be recycled, the opportunity cost of using water depends on the final state and location of the water after the user has finished using it. For agricultural users, some parts of the used water evaporate and some seeps into groundwater, eventually returning to the system. Depending on the location, industrial users evaporate wastewater, send it to treatment facilities for treatment and release to rivers and streams, or inject it for storage underground. This means agricultural users and hydraulic fracturing well owners will have different impacts on the water management system. Holmes' (2012) work illustrates how effects of water use depend on wastewater disposal method and water use abatement technology.

He concludes that since in the case of Alberta the regulator (here, Alberta Environment) does not have precise information on each water user's effects, policies regarding water related sectoral inter-dependence and water allocation are uncertain.

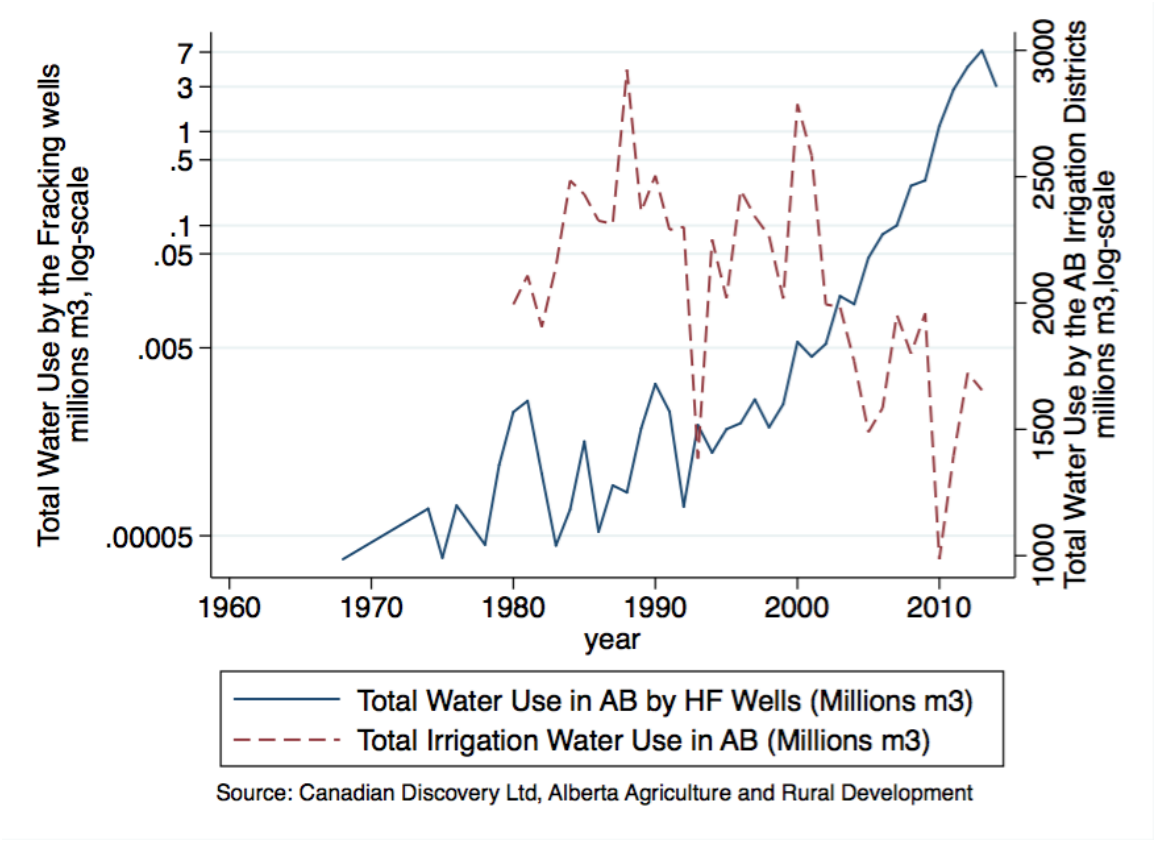


Figure 8.3. Total Water Use by the Hydraulic Fracturing Wells in Alberta, 1968-2013 and Agricultural Sector's Irrigation Water Use in Alberta, 1980-2013.

Figure 8.3 shows total water use by the hydraulic fracturing wells and total water used by the agricultural sector for irrigation purpose, using data from Canadian Discovery's WCFD and Alberta Agriculture. Under regular weather conditions it is likely that there is no substantial effect of the hydraulic fracturing wells' water use on irrigation water use in Alberta since water used for irrigation is significantly higher than the amount used for hydraulic fracturing. Nevertheless, hydraulic fracturing water use can have effects if the intensity requires a larger amount of water within a short time span compared to the other sectors. This difference could be crucial and hydraulic fracturing water use can have impacts during a prolonged drought or severe water scarcity.

8.3 Knowledge Gaps

There is little research regarding the direct impact of hydraulic fracturing on water quantity used by other major sectors such as agriculture. Further studies are warranted to examine the effect of hydraulic fracturing on the agricultural sector's water use for irrigation (e.g. are farmers selling their allocated water to hydraulic fracturing well operators?). In Alberta, an understanding gap exists regarding

whether the water usage policy of Alberta Environment ensures optimal water allocation. As shale gas development continues, possibly expanding to areas with little or no previous hydraulic fracturing activity, this question will become more pressing, both in Alberta and other provinces.

8.4 Range of Research Approaches

No empirical analysis has examined the impacts between oil and agriculture by exploiting variation in use over time and space. A possible approach could be for the researcher to do some statistical analysis, given that there is a standard dataset containing fracturing water volume in proportions of fresh/saline and surface/groundwater/wastewater upstream of an irrigation district, in order to measure the effects on agricultural irrigation water volume downstream. If there is an existing water market system, like the one in Alberta stated above, then the dataset should also include the source of water for hydraulic fracturing and the price of the water paid by the well owners if the source is from agricultural water allocation. This statistical analysis should be able to conclude if the agricultural sector's water use activity is being influenced by the water activity of the fracturing sector.

Table 8.1. Range of practical research approaches to address knowledge gaps

	Research Approach 1: Complete analysis of the source of the water used for hydraulic fracturing	**Research Approach 2:** Effect of hydraulic fracturing water use on existing water market	**Research Approach 3:** Measuring the impact on other major users (considering the capacity of the watershed)
Complexity	Low; the main step of this study is to collect the data.	Moderate; the most important feature of this research is to explain if hydraulic fracturing is causing more water trading in the existing water markets in Canada.	High; study should answer why or why not hydraulic fracturing water use is not a threat to other water users.
Risk/ Uncertainty	Major difficulty: scarcity of reliable data on water-source for hydraulic fracturing in Canada.	Risk: not enough information regarding water trading. If all water trades are not reported to the government, then trade data will be scarce.	Risk: Possible scarcity of reliable data. If the users do not report the effects from hydraulic fracturing, then this study might not produce unbiased results
Timeframe	Moderate; 1 to 1.5 year minimum	Moderate; 1 years minimum	Moderate; 2 year minimum
Cost	Low; $100,000	Moderate; $150,000	Moderate; $200,000
Research Capacity	High; econometrician.	High; econometrician and water- policy expert.	High; econometrician and GIS expert.
Difficulty of Implementation	Low; statistical analysis.	Low; statistical analysis.	Moderate; statistical analysis.
Likely Achievements	This research work consists of two steps. The first step is to collect the available data on the water-source used by the hydraulic fracturing wells in Canada. The second step is to summarize the water used in major plays in Canada- in the fracking-fluid what percentage of water is fresh (from ground and surface water source) and what percentage is produced water.	This work should identify and compile the data on the volume and source of water used by hydraulic fracturing and then use this data to detect whether hydraulic fracturing is altering the existing water market in any parts of Canada, and how the total water demand and supply is being affected (or not).	Using data on water quantities and sources for hydraulic fracturing in Canada, this study would examine the effect hydraulic fracturing has on other water users, such as the agricultural sector.

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SECTION 9: What are the True Costs (Including Externalities) of Hydraulic Fracturing?

9.1 Introduction

Most studies estimating the impacts arising from hydraulic fracturing address narrow research questions (e.g., how are shale gas wells capitalized in the housing market). A confident estimate of the net effect of hydraulic fracturing activity or shale gas development is not yet available. To identify whether fracturing is a welfare-improving activity, a complete study should be pursued listing all costs and risks caused by fracturing. This cost-benefit analysis would help the policymakers making decisions.

The scope of this CWN project is to discuss water and therefore the focus of this literature review is on studies that attempt to estimate the costs associated with impacts on water resources specifically. Various risk pathways are associated with hydraulic fracturing, but the studies discussed here are singled out for their attention to either groundwater or surface water impacts.

9.2 Literature Review: Risks and Costs Associated with Hydraulic Fracturing

9.2.1 A Discussion of Overall Risks

A Resources for the Future expert panel report (RFF, 2013) followed a survey-based approach to develop a risk matrix that identifies the routine and accidental channels through which risks can originate.[1] They gave a panel of 215 experts different sets of questionnaires and identified the risks for which there was the most consensus across the industry, academic, NGO, and government experts. Figure 9.1 lists the potential risks.

[1] The complete risk matrix is available here: http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale-Matrices.aspx#top

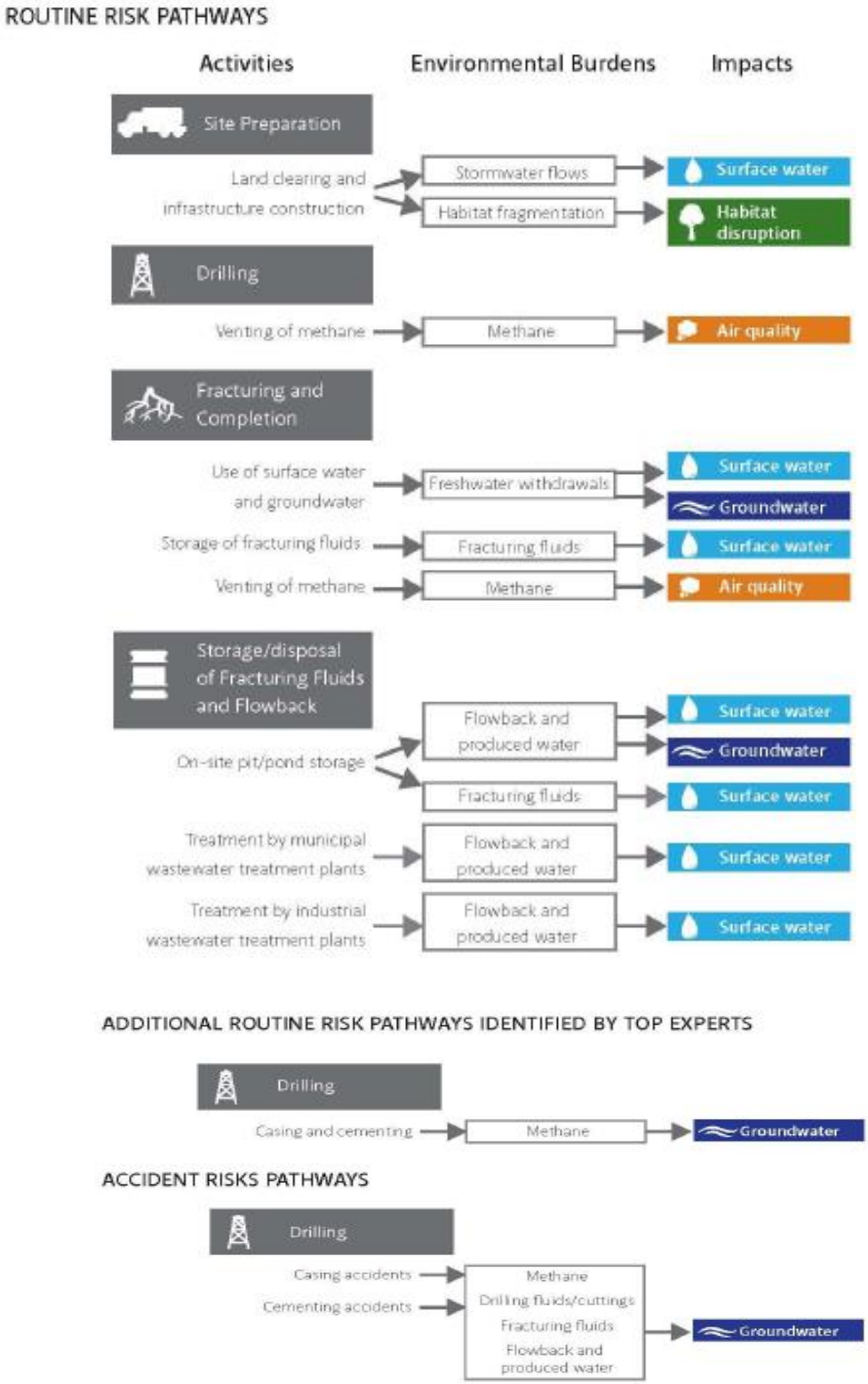

Figure 9.1: Risk arising from routine pathways and additional pathways from shale gas development (RFF, 2013)

The twelve risks for which there was consensus cover risks to surface water, air quality, groundwater, and habitat disruption.

9.2.2 Economic Valuation

Economists usually divide economic value of a natural resource into two categories, use value and non-use value. Use value from an underground aquifer would include the benefits it provides as a drinking water source, but also the option value of using it in the future. The non-use value would include the value placed on its existence or from its bequest value. There are two types of methods that economists use to estimate these values. The first is a "stated preference" approach where individuals are asked what they would be willing to pay. Often this is the only method available to researchers to assign a dollar value to a non-use environmental amenity. The second method is a "revealed preference" where actual behavior is observed and used to infer prices. For example, if there is a market for water, one could simply look at the price that the water is sold. There are also indirect measures when there is no market for the amenity at hand, such as looking at how much people are paying for bottled water. Both stated and revealed preferences can be used to estimate the magnitudes of the negative externalities associated with shale gas development.

9.2.3 A Revealed Preference Approach: Obtaining an Estimate of the Capitalization of Groundwater Contamination Risks

To measure the net effect of shale gas development on the housing market, Muehlenbachs et al. (2014) conducted an empirical analysis using data from Pennsylvania and New York shale gas fields. They recovered hedonic estimates of property value impacts from shale gas development, which vary by geographic scale, water source, well productivity, and visibility. They concluded that properties dependent on their own private drinking-water wells without access to piped water are negatively affected by nearby shale gas development. The differential effect of shale gas development for groundwater-dependent properties relative to those properties with access to piped water gives valuable insight into the capitalization of groundwater contamination risk. Properties with access to piped water are positively affected by nearby shale gas wells unless the property depends on groundwater. In other words, according to Muehlenbachs et al. (2014), proximity to wells increases property values, but groundwater contamination concerns fully offset those gains.

9.2.4 State Preference Approaches: Conducting Surveys to Obtain People's Willingness to Pay to Reduce Risk to Water Resources

In order to measure people's willingness to pay to reduce risk from shale gas development, Siikamäki and Krupnick (2014) conducted a survey of two random samples of people living in Texas and Pennsylvania. Using these samples, they found that people in both Texas and Pennsylvania are supportive of shale gas development, but they differ in the amount they are willing to pay to reduce risk. Siikamäki and Krupnick (2014) found Texans are willing to pay more in some respects such as to reduce surface water-related risks while people from Pennsylvania are more willing to pay for improvements in groundwater. They also found that people's willingness to pay to reduce risk is sensitive to the information they are first given (e.g. statements from industry groups or statements from environmental advocacy groups). In another study, Bernstein et al. (2013) survey residents of

Susquehanna Valley region in central Pennsylvania to measure people's willingness to pay for protecting river water from potential contamination arising from shale gas extraction process. In their survey, a sample of 186 Susquehanna valley residents were asked how much they are willing to pay for improved water access and additional safeguards against possible contamination caused by shale gas development. The survey results suggest households are willing to pay an average of 10.46$US per month for additional safety measures that would reduce risks to local watersheds from drilling to extract shale gas. Bernstein et al. (2013) conclude their measurement of household's willingness to pay for protecting surface water from drilling can be compared with the costs of providing safeguards against potential risks from shale gas development.

9.2.5 Measuring Human Health Related Risk Directly

Here we focus on studies in the intersection of health and risk to water resources from hydraulic fracturing. To determine the relationship between households' reported health conditions and proximity to natural gas wells, Rabinowitz et al. (2015) conducted a survey of 492 people in 180 randomly selected households. Their study focused on Washington County in southwestern Pennsylvania, an active natural gas drilling area where all the wells mostly use groundwater. There were 624 active natural gas wells, of which 95% were horizontally drilled. Rabinowitz et al. found an increased frequency of reported symptoms over the past years in households in closer proximity to active gas wells relative to households farther from gas wells. Furthermore, they also found similar increases in the reported symptoms of other categories like skin diseases and upper respiratory symptoms, controlling for age, gender, and other related variables. The authors concluded that further investigation is required to confirm whether hydraulic fracturing is associated with community health impacts.

To observe the relationship between shale gas development and infant health, Hill (2013) constructed a dataset containing the latitude and longitude of the hydraulic fracturing wells and street address of all new mothers in Pennsylvania. Using an econometric regression analysis, Hill concluded that shale gas development increased the incidence of low birth-weight and small for gestational age (SGA) in the vicinity of a shale gas well by 25 percent and 18 percent, respectively. However, the results do not differ across water sources which suggest that groundwater contamination does not play a role here; rather, air pollution and stress from localized economic activity are the key reasons. McKenzie et al. (2014) examined the association between maternal residential proximity to natural gas development (NGD) and birth outcome in Rural Colorado for the period 1996 to 2009. The authors found that there is correlation between density and proximity of natural gas wells and the prevalence of congenital heart defects (CHD). Moreover, the authors also found there could be some possible association with neural tube defects (NTD) and proximity to NGD. However, they concluded that more specific exposure estimate is required to further explore and justify these associations. When Colborn et al. (2012) explained the effects of prolonged exposure of the hydraulic fracturing chemicals on human health, they confirmed that more than 75% of the chemicals used in hydraulic fracturing could affect the skin, eyes, and other sensory organs along with the respiratory and gastrointestinal systems. However, these last two studies do not differentiate between households dependent and not dependent on private groundwater wells.

9.3 Knowledge Gaps

The true cost of hydraulic fracturing depends on economic and other benefits weighed against various risks. For instance, what is the willingness to pay to avoid water resource rick in Canada, and what are the indirect externalities from water use in hydraulic fracturing? While several studies exist that address individual risk pathways, a large understanding gap remains regarding the overall cost of hydraulic fracturing.

9.4 Range of Research Approaches

In the existing studies two basic approaches can be observed to measure costs of the fracturing activity: stated preference (e.g., Siikamäki and Krupnick, 2014) and revealed preference (Muehlenbachs et al., 2014). In choice modeling, stated preference is a choice experiment which extracts an individual's preferences as taken from questionnaires. This is the only method available to researchers to assign a dollar value to a non-use environmental amenity. Critics of this approach prefer to use revealed preferences where willingness to pay is measured from market activity rather than eliciting willingness to pay from a survey. Revealed preference based study to measure willingness to pay (WTP) to reduce loss from hydraulic fracturing has been conducted in USA (e.g. Siikamäki and Krupnick, 2014) but it is not yet available in the context of Canada. Both of these methods can be used to estimate the magnitudes of the negative externalities associated with shale gas development.

Despite the paucity of data on the physical and economic magnitudes of negative externalities, it is possible to draw some important conclusions. First, many of the externalities from hydraulic fracturing are not priced, so even without estimates of their magnitude, the social costs associated with fracking are likely larger than the private costs. Second, despite the presence of negative externalities, the magnitude of benefits (from the abundance of natural gas to producers and consumers) suggests a very high “burden of proof” for those who would support forgoing, or very significantly constraining, shale gas production on economic grounds. Third, unpriced social costs are mainly local in nature, while its benefits are local, national, and global. A complete cost benefit analysis is yet to be completed but is warranted and the potential costs should cover both groundwater quality and quantity effects influencing all socio-economic activities. And finally, it is also very important for policymakers to keep the long-term maintenance and upkeep of wells into consideration. The monitoring, maintenance, and repair of faulty well casings is only more difficult once wells reach the end of their productive lifetimes, especially if the original licensee is insolvent. Therefore, policies that incentivize precautions to protect groundwater now as well as in the distant future are warranted.

Table 9.1 Range of practical research approaches to address knowledge gaps.

	Research Approach 1: Stated Preference	**Research Approach 2:** Revealed Preference	**Research Approach 3:** Complete cost-benefit analysis
Complexity	Methodology on revealing individual willingness-to-pay is well defined.	Methodology would have to be adapted depending on the question. It will be a statistical analysis using variation over time and geography.	This would be a meta-analysis of existing studies
Risk/Uncertainty	N/A	N/A	N/A
Timeframe	Moderate; 1 to 1.5 year minimum	Moderate; 2 years minimum	Moderate; 2 years minimum
Cost	Moderate; $300K	Moderate; $100K to $500K	Moderate; $200K
Research Capacity	High; need one expert in contingent valuation. Can outsource survey implementation to a company.	High; econometricians and GIS specialists would be necessary.	High; three economists.
Difficulty of Implementation	Low; will involve constructing and conducting a survey of a random sample of households in Canada and then analyzing the responses.	Moderate to high; for example, using property sales, would need a long history of data, to be able to have information on a property before and after a well is drilled.	High; involves identifying all possible costs and benefits. Literature on the costs and benefits is still in a nascent stage
Socio-Political Concerns	N/A	N/A	N/A
Likely Achievements	Surveys of the general public would reveal the willingness to pay to avoid risks of hydraulic fracturing to water resources in Canada, or willingness to accept to live in proximity to hydraulic fracturing.	Revealed preference methodology examines individual's taken actions to estimate the individual's willingness-to-pay. For example, data on property sales in Canada could be used to estimate willingness to pay to avoid living near a shale gas well.	In a complete cost-benefit analysis, research would state all potential positive and negative effects of hydraulic fracturing. Thus this research should calculate the net effect of hydraulic fracturing, illustrating whether it is welfare increasing or decreasing.

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SECTION 10: Fate of Chemicals Used in Hydraulic Fracturing, and Flowback Water Disposal by Deep Well Injection

This final section contains two knowledge gaps that were not ranked particularly highly by the research team, but are included since they are salient to the issues at hand. The fate of chemicals used in hydraulic fracturing are somewhat related to deep well injection insofar as much of the fluid used in hydraulic fracturing is returned to surface as flowback water prior to disposal by deep well injection. The concern for induced seismicity due to deep well injection is covered in Section 5, and this topic is not repeated here. Since these topics were not ranked as high priority, and since the major knowledge gap for deep well injection is already addressed in Section 5, no ranges of research approaches are presented here.

10.1 Introduction

Fate of chemicals used in Hydraulic Fracturing

Public concern over the use of chemical additives in fracturing fluids was the issue that initially brought shale gas and hydraulic fracturing under public scrutiny (Boling, 2013). The initial public concern was centered on two factors: many of these chemicals have potential human health impacts (Colburn et al., 2011), and there was initially no requirement to disclose what chemicals were used for any given well.

Although over 600 chemical additives have been used in hydraulic fracturing (GWPC, 2009), individual fracturing fluids tend to contain less than a few dozen additives (e.g. Figure 10.1). The wide variety of fracturing chemicals is designed to impart a variety of desirable engineering and chemical properties to the injection fluids. The desired properties vary as a function of properties of the target zone (e.g. geochemistry, microbiology, geological characteristics), well (e.g. total length, type of materials), source water, and proppant (i.e. the sand that is included in the fluid to 'prop' open fractures as they are created). Chemicals used in hydraulic fracturing (Figure 10.2) include scale inhibitors to prevent precipitation of carbonate and sulfate minerals; surfactants (detergents) to increase recovery; friction reducers (e.g. petroleum distillates) to minimize friction between the well and injected fluid and to increase the distance that proppant travels into fractures; corrosion inhibitors to protect downhole infrastructure; acid to dissolve the shale minerals and increase fracture size; crosslinkers and gelling agents to maintain higher viscosity in the fracturing fluid to carry proppant more effectively; and biocide to control bacterial growth (EPA, 2010; The Royal Society and Royal Academy of Engineering, 2012). The chemicals used and relative proportions vary on a well-to-well basis, and also within individual fracture treatments (i.e. the fracturing fluid composition varies from the beginning to the end of the treatment in each hydraulic fracturing stage).

Hydraulic Fracturing Fluid Product Composition

Start/End Date:	Component Type	Trade Name	Supplier	Purpose	Ingredient Family Name	CAS # / HMIRC #	Concentr. in Component (% by mass)	Concentr. in HFF (% by mass)
Mar 2 2015 - Mar 3 2015	Carrier fluid				N2	7727-37-9	100%	20.950939%
	Carrier fluid				water	7732-18-5	100%	46.854919%
	Carrier fluid				water	Not available	85%	3.046682%
	Carrier fluid				Hydrochloric acid	7647-01-0	15%	0.537649%
	Proppant	Sand 20/4(	Trican		silica crystalline	14808-60-7	100%	26.702748%
	Additive	PCB-1	Trican	Breaker	severely refined mineral oil	Trade Secret	100%	0.056702%
	Additive	CC-7	Trican	Clay Control	water	7732-18-5	85%	0.085651%
	Additive	CC-7	Trican	Clay Control	1,6-hexanediamine dihydrochloride	6055-52-3	40%	0.040306%
	Additive	AI-7N4	Trican	Corrosion Inhibitor	modified propargyl alcohol	Trade Secret	100%	0.014865%
	Additive	AI-10	Trican	Corrosion Inhibitor	acetone	67-64-1	30%	0.001862%
	Additive	AI-10	Trican	Corrosion Inhibitor	formic acid	64-18-6	30%	0.001862%
	Additive	AI-10	Trican	Corrosion Inhibitor	polyoxyalkylenes	68951-67-7	30%	0.001862%
	Additive	AI-10	Trican	Corrosion Inhibitor	fatty acids	9231	10%	0.000621%
	Additive	AI-10	Trican	Corrosion Inhibitor	modified thiourea polymer	9231	10%	0.000621%
	Additive	AI-10	Trican	Corrosion Inhibitor	methanol	67-56-1	5%	0.000310%
	Additive	AI-7N4	Trican	Corrosion Inhibitor	Propargyl alcohol	107-19-7	0.90%	0.000134%
	Additive	DF-1	Trican	Defoamer	non-hazardous ingredients	Not available	100%	0.000334%
	Additive	IC-2	Trican	Iron Control	sodium erythorbate	6381-77-7	100%	0.022297%
	Additive	IC-3	Trican	Iron Control	sodium nitrilo-triacetate monohydrate	18662-53-8	100%	0.014777%
	Additive	MS-7	Trican	Solvent	poly(oxy-1,2-ethanedlyl), a-hexyl-w-hydroxy	31736-34-8	100%	0.631632%
	Additive	FC-2	Trican	Surfactant	water	7732-18-5	65%	0.027023%
	Additive	ASA-60W	Trican	Surfactant	dipropylene glycol	25265-71-8	60%	0.025240%
	Additive	S-8	Trican	Surfactant	methanol	67-56-1	60%	0.003121%
	Additive	FC-1	Trican	Surfactant	N,N,N-trimethy-1-octadecaminium chloride	112-03-8	60%	0.389511%
	Additive	ASA-60W	Trican	Surfactant	alkylbenzenesulfonic acid	68584-22-5	40%	0.016827%
	Additive	FC-1	Trican	Surfactant	isopropanol	67-63-0	40%	0.259674%
	Additive	FC-2	Trican	Surfactant	organic salt	9292	40%	0.166294%
	Additive	S-8	Trican	Surfactant	oxyalkylated alkylphenolic resin	30704-64-4	30%	0.001560%
	Additive	ASA-60W	Trican	Surfactant	sodiaum hexyldiphenyl ether sulfonate	147732-60-3	13%	0.005469%
	Additive	FC-1	Trican	Surfactant	N,N,N-dimethy-1-octadecamine	124-28-7	5%	0.032459%
	Additive	FC-1	Trican	Surfactant	N,N,N-dimethy-1-octadecamine-HCL	1613-17-8	5%	0.032459%
	Additive	S-8	Trican	Surfactant	polyglycol diepoxide	68036-92-0	5%	0.000260%
	Additive	S-8	Trican	Surfactant	polyglycol diepoxide	68036-95-3	5%	0.000260%
	Additive	S-8	Trican	Surfactant	solvent naphtha (petroleum), light aromatic	64742-95-6	5%	0.000260%
	Additive	S-8	Trican	Surfactant	xylene	1330-20-7	5%	0.000260%
	Additive	S-8	Trican	Surfactant	1,2,4-trimethylbenzene	95-63-6	1%	0.000052%
	Additive	S-8	Trican	Surfactant	1,3,5-trimethylbenzene	108-67-8	1%	0.000052%
	Additive	S-8	Trican	Surfactant	ethylbenzene	100-41-4	1%	0.000052%

Figure 10.1. Example of a Hydraulic Fracturing Fluid Composition for Well License 0474198 from FracFocus.ca on chemical additives used in hydraulic fracturing fluids for a well in Alberta. The report includes the chemical components, and their concentration in the additive and in the hydraulic fracturing fluid as percent composition by mass (accessed from FracFocus.ca, April 16, 2015).

The U.S. Environmental Protection Agency began a multi-phase study into the 'theoretical potential' for hydraulic fracturing fluids used in coal bed methane development to affect groundwater sources for

drinking water (where coal beds were not located in the drinking water aquifers; EPA, 2004). Ingelson and Hunter (2014) reported that public concern about the injection of fracturing water containing additives into the subsurface was allayed after the 2004 EPA report concluded that there was "no evidence directly linking hydraulic fracturing to water contamination", which posed "little or no threat to drinking water sources". This conclusion was based on three main points: much of the hydraulic fracture fluid was recovered by 'flowback', the existence of 'significant geologic barriers' (like shale), and other 'underground mitigating effects' (Ingleson and Hunter, 2014). Other researchers, but not all (e.g. Myers, 2012), have also concluded that direct pathways between the hydraulic fracturing target zone and shallow groundwater zone are possible, but not likely (Jackson et al., 2013; Flewelling et al., 2014, Darrah et al., 2014; Vidic et al., 2014; c.f. Sections 1 to 3).

Likely in response to public concern, the shale gas industry (as represented by the Canadian Association of Petroleum Producers; CAPP) actively supported disclosure of fracturing fluid composition (Bott et al., 2013). No federal regulations exist regarding chemical information disclosure (Maule et al., 2013), but state and provincial regulatory agencies in North America and Australia have responded to the public concern by requiring public disclosure of some information about fracturing fluid additives (Ingelson and Hunter, 2014). Both carrier fluids and additives (including their percent composition by mass) have been made publicly available since January 1, 2012 for British Columbia and January 1, 2013 for Alberta in the 'Frac Focus Chemical Disclosure Registry' (fracfocus.ca) hosted by the BC Oil and Gas Commission. Reporting requirement exceptions were made for 'trade secret' ingredients (i.e. those that 'represent a unique competitive advantage to [the] owner of the intellectual property associated with the ingredient, formulation or use' that are subject to a claim exemption under the Hazardous Material Information Review Act. A claim of exemption must be filed with the Hazardous Materials Information Review Commission (HMIRC) under the Hazardous Materials Information Review Act for a chemical to be considered a trade secret (B.C. Oil and Gas Commission, 2012b; AER, 2012a). Information on the trade secret is accessible by certain government officials and medical professionals under specific circumstances (Minister of Justice, 2013). The chemical disclosure registry includes chemical registry numbers (either those assigned by the American Chemical Society's Chemical Abstracts Service Division (CAS) or by the HHMIRC for all additives (except non-toxic or 'trade secret' ingredients), facilitating the procurement of information about each chemical.

A German research team reviewed safety data sheets that were available for 80 of 88 commercial hydraulic fracturing products and reported that 27 of the 80 were classified as 'non-toxic', six as 'toxic', six as 'dangerous to the environment', 25 as 'harmful', 14 as 'irritants', and 12 as 'corrosive' (with several products falling into more than one of the classifications; Bergmann et al., 2014). They similarly compared the chemicals to a German natural water hazard classification and reported 10 chemicals were 'non-hazardous', three were 'severely hazardous', 12 were hazardous, and 22 were low hazard.

Chemical properties related to their fate and transport in groundwater (e.g. solubility, sorption affinity, rate of degradation and degradation pathway(s), and tendency to bioaccumulate) have not been collated or assessed for many of the fracturing chemicals (Bloetvogel et al., 2013). In some cases these properties are likely not yet known and would require new investigation. Further, none of the chemical

properties would have been evaluated at the higher pressures and temperatures in the deep (and to a lesser degree intermediate) zone (Bloetvogel et al., 2013).

In most cases oilfield service companies specialize in the development of appropriate composition of hydraulic fracturing fluids. Since the effectiveness of fracturing fluids is directly related to well productivity (Armstrong, 1995), new additives are being actively developed and evaluated on an ongoing basis (e.g. Labena et al., 2014; Pizadeh et al., 2014; Sun et al., 2014).

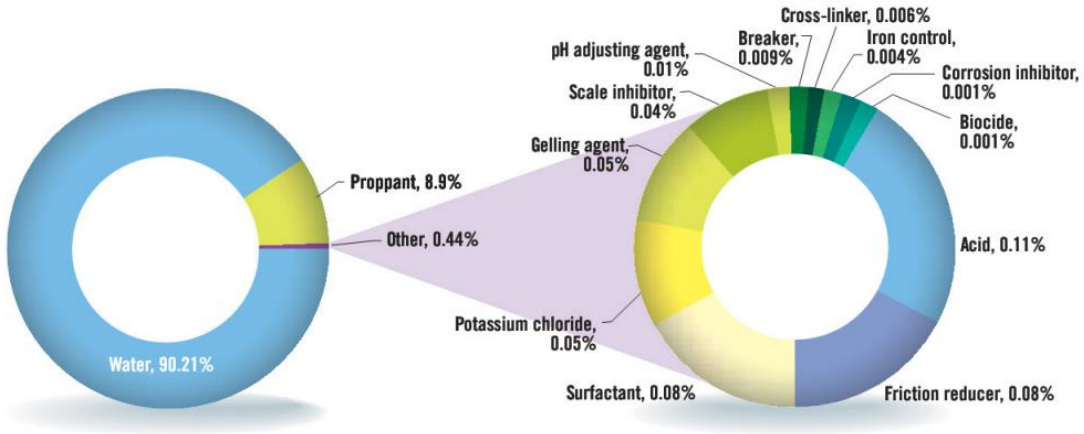

Figure 10.2. Typical compositional make-up of fracturing fluid (after Saba, 2014).

Deep Well Injection

Deep well injection (DWI) of wastewater has long been practiced in North America. Co-produced water was re-injected into producing wells as early as the 1920s and 1930s both for disposal and to 'repressurize' oil reservoirs (also known as secondary recovery). In particular, secondary recovery was instructive in understanding the limits of DWI since it often entailed "large arrays of wells injecting fluids at high pressures into small confined reservoirs that have low permeabilities" as opposed to waste disposal wells which were ideally designed to "inject at lower pressures into large porous aquifers that have high permeabilities" (Nicholson and Wesson, 1990). There is not always a clear distinction between DWI wells and petroleum wells. In fact petroleum wells are sometimes 're-purposed' as injection wells. About 50,000 of the 700,000 wells historically drilled for petroleum in the Western Canadian Sedimentary Basin (WCSB) have been used for DWI (Fergusson, 2014).

Wastes from various other sources were also being injected in the 1960s, notably including the chemical, refining, and mining industries (Piper, 1969; Van Everdingen and Freeze, 1971). The use of DWI increased notably after the U.S. Clean Water Act restricted direct discharge of wastewater in surface waters (Rima et al., 1971). In the late 1960s, a reported 110 injection wells were in use in the U.S. (Water Well Journal, 1968), while 31 industrial waste disposal wells were operating in Canada (Van Everdingen and Freeze, 1971). A median injection depth of about ~800 m reported in the 1960s (Piper, 1969) is similar to that reported today – about 800 m in BC (B.C. Oil and Gas Commission, 2010) and 1000 m in Alberta (Fergussen, 2014). Interestingly, one paper reported on hydraulic fracturing of a shale

formation to evaluate nuclear waste disposal possibilities in Tennessee at depths that would be considered very shallow today (~300m; Weeren, 1966).

Like most industrial activities, DWI has suffered from some failures and adverse issues, the most widely cited of which was induced seismicity at the Rocky Mountain Arsenal in Colorado caused by DWI in the 1960s (c.f. Section 5). Other issues include the breakout of saline formation water to shallow groundwater near Sarnia in the 1970s (Lesage et al., 1991), and land uplift ranging from a few mm to tens of cm due to deep well injection for a range of activities including aquifer storage and recovery, enhanced oil recovery, gas storage, and DWI specifically to mitigate land subsidence (Teatini et al., 2010). Nicholson and Wessen (1990) report two incidences of induced seismicity by DWI in Canada (Mereu et al., 1986; Milne, 1970).

Deep well injection wells are classed according to the characteristics of fluid being injected, regardless of the injection purpose. Most jurisdictions have well classification that is similar to that used by the U.S. EPA (2015). In Canada, the provinces hold the main authority to regulate deep well injection. In Alberta, the Alberta Energy Regulator's Directive 51 (Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements; AER, 1994) defines the classes of wells according to the characteristics of the wastes being disposed of by DWI. Flowback water typically falls into Class 1b (produced water/brine equivalent). The "Resources Applications for Oil and Gas Reservoirs" (Directive 65; AER, 2014) stipulates the requirements for assessing and assigning the maximum wellhead injection pressure. Similarly, the B.C. Oil and Gas Commission uses a "Procedure for Authorizing Deepwell Disposal of Wastes" where Class 1b wells are those used for the disposal of produced water. The western provinces, which have the most injection wells in Canada, have slightly different approaches to determining the maximum wellhead pressure, and regulate maximum injection pressures slightly differently. The B.C. Oil and Gas Commission limits DWI injection pressures to 90% of formation fracture pressure, with an ultimate reservoir "fill-up" limit of 120% of the virgin formation pressure (B.C. Oil and Gas Commission, 2010), while the AER's Directive 51 states that injection pressures will be the lesser of i) 90% of the maximum injection pressure or ii) the pressure at which hydraulic isolation logging was conducted (AER, 1994). Most DWI in western Canada is conducted by third-party providers.

The injection of 'fresh' or shallow water is typically strongly discouraged in DWI policies (e.g. EPA, 2015). For instance, both British Columbia and Alberta's approaches hold that resource conservation of fresh water shall be pursued whenever possible, and that water conservation and/or treatment and return to the surface or watershed is the preferred waste management option. In British Columbia, hydraulic fracture flow-back water may be recycled for additional fracture treatments but must ultimately be disposed by DWI, as there is currently no ongoing treatment that meets standards for surface release (B.C. Oil and Gas Commission, 2010; AER, 2014). Policies in both provinces forbid the DWI of municipal sewage, however a novel project in British Columbia treats one town's municipal waste water as a water supply for hydraulic fracturing. Hydraulic fracture flowback fluid cannot be disposed to municipal water treatment facilities.

In the U.S., as in Alberta, the majority of DWI is related to oilfield activity (EPA, 2015; Fergusson, 2014). British Columbia has had DWI since the 1960s, for saline water by-product of conventional oil and gas

wells, but DWI activity has increased rapidly in concert with hydraulic fracturing (B.C. Oil and Gas Commission, 2010). Deep well injection associated with disposal of flowback water from hydraulic fracturing is a departure from historic DWI in the oil and gas industry insofar as about 20% of the flowback water in hydraulic fracturing originated from the near-surface freshwater environment (i.e. surface water or shallow groundwater; CAPP, 2011). This constitutes loss of fresh water from the active, near-surface hydrologic cycle into deep formations with residence times measured on the geologic timescale. This concern is related to Sections 6 and 7, and not covered here.

10.2 Literature Review

The Council of Canadian Academies report (CCA, 2014) on the Environmental Impacts of Shale Gas Extraction in Canada observed that there was only minimal reference literature and no peer-reviewed literature that assesses the potential for the various chemicals in hydraulic fracturing fluids to persist, migrate, and impact the various types of subsurface systems or to discharge to surface waters. There is still very little understood about the behavior of many of the chemical additives and mixtures, and their potential degradation products and pathways under variable *in situ* conditions including salinity, temperature, pressure, pH and redox state for example (Blotevogel et al., 2013).

A report published in August, 2014 identified ethylene oxide (EO) surfactants in hydraulic fracturing flowback and produced water using analytical techniques (Thurman et al., 2014). A major goal of the study was the identification of the EO surfactants and the construction of a mass spectral database with accurate masses and retention times in order to allow identification of the wide variety of chemicals used in hydraulic fracturing fluids. The technique was applied to a series of flowback and produced water samples to illustrate the usefulness of ethoxylate “fingerprinting”. This report is the first known of its kind, which examines the fate of chemicals used in hydraulic fracturing fluids.

The fate of injected hydraulic fracturing fluid that does not flow back is not clearly known. Concerns around injected water are the migration of the water into the shallow groundwater zones and subsequent contamination of groundwater resources. One possibility (with the highest probability) is that the water (and presumably the chemicals contained) is imbibed by the target formation (Engelder et al., 2012; Cheng et al., 2015; Birdsell et al.,2015). As discussed earlier in this report, possible source pathways for fluid migration to the shallow zone could be leaky wellbores, nearby old or operating wells with faulty seals or improperly decommissioned well bores (also known as ‘offset wells’), as well as natural and induced subsurface pathways (i.e. natural or induced fractures and faults). As discussed, the growing consensus seems to be that these pathways are not likely (c.f. Sections 1-3).

Since DWI has long been practiced there is relatively little ‘new’ literature related to shale gas development, with the exception of new evidence for induced seismicity (as discussed in Section 5) and the concern for the systematic DWI of freshwater contained within the flowback water (c.f. Sections 6 and 7). The largest concern around DWI remains the potential for induced earthquakes to breach the confining layer of a waste-disposal reservoir, which could induce earthquakes and/or permit the

possible upward migration of contaminated fluids through new pathways (Nicholson and Wesson, 1990).

Fergussen (2014) notes that increased DWI associated with hydraulic fracturing has become contentious in the WCSB. Although the volume of water injected by DWI over the past number of decades (23 km^3 of which 20 km^3 was co-produced water) has exceed natural recharge by two to three orders of magnitude). The surplus 3 km^3 of water injected by DWI in the WCSB is slightly less than the volume of oil that has been produced over the same time period (4.3 km^3). The 1.3 km^3 estimated net change in WCSB fluid storage is small compared to 200,000 km^3 of pore volume estimated by Hitchon (1968).

Fergusson (2014) acknowledges that although there have been few documented cases of environmental problems related to injection wells, the lack of a comprehensive monitoring approach 'makes it difficult to dismiss concerns about the environmental impacts of injection'.

10.3 Knowledge Gaps

Two knowledge gaps are considered here in the context of hydraulic fracturing and chemical additives. Overall, the migration patterns and subsurface fate and behavior of hydraulic fracturing fluid additives are poorly understood. Although there is growing consensus that out-of-zone migration is not likely, there remains little knowledge about the environmental fate of the associated chemicals. Until the fate of injected water that does not flow back is better constrained, we suggest the following two knowledge gaps are relevant:

a) *What are the parameters related to their environmental fate?*
b) *What happens to injected water that does not flow back*?

No new knowledge gaps are presented for deep well injection since they are previously covered in Section 5.

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