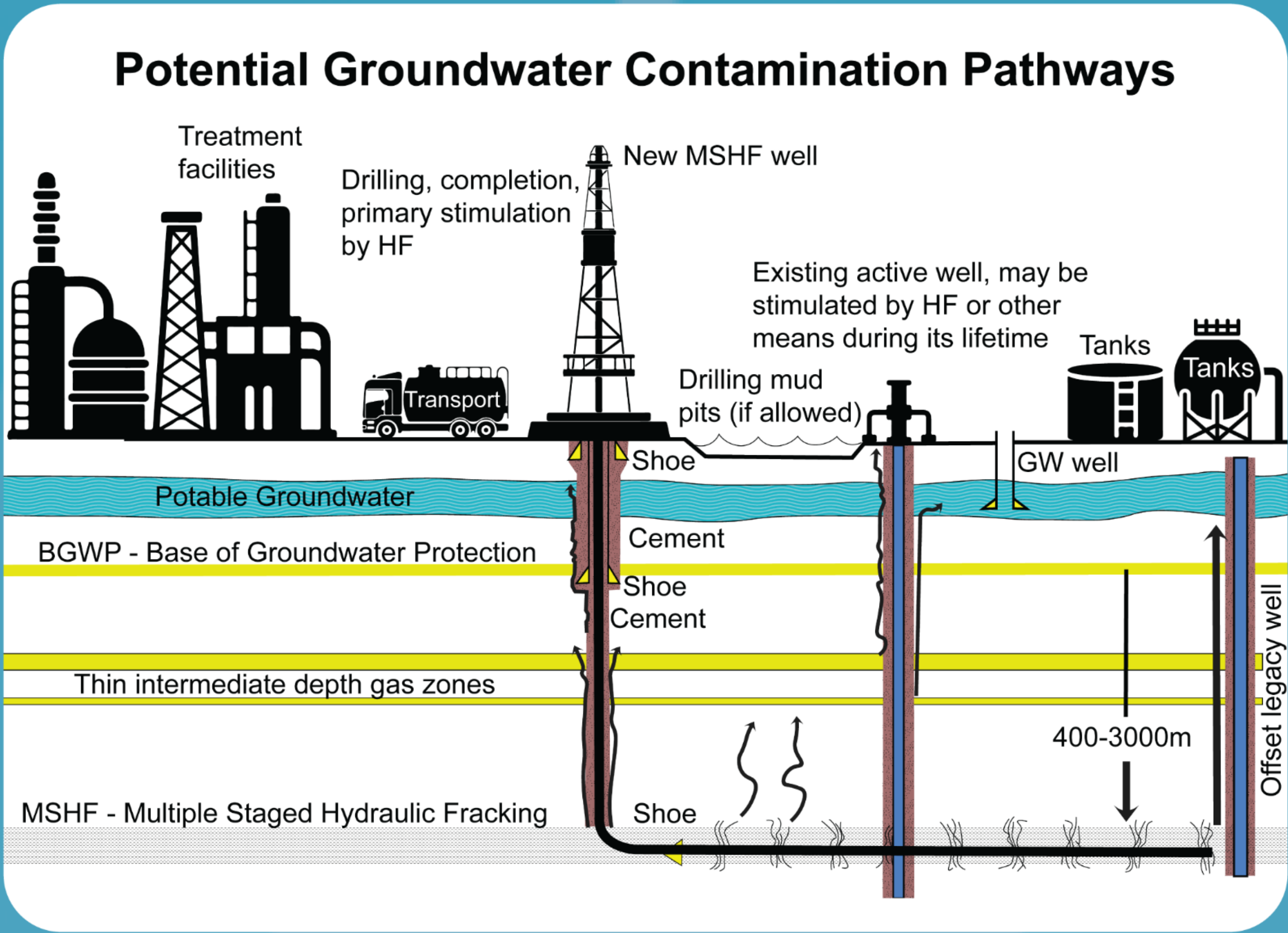

Groundwater Contamination and Geoenvironmental Impacts of Upstream Oil and Gas Production

Richard E. Jackson, Robert F. Walsh, Mary Kang and Maurice B. Dusseault

THE GROUNDWATER PROJECT

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THE GROUNDWATER PROJECT

Cover Image: Maurice Dusseault, University of Waterloo, 2023.

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The Groundwater Project Foreword

The 2022 United Nations (UN) World Water Day theme "*Groundwater – Making the Invisible Visible*" was pivotal in raising global awareness about groundwater as an invaluable resource, and the year concluded with the UN Water Summit on Groundwater at the UNESCO headquarters. One of the key outcomes of the Summit was a call for governments and other stakeholders to scale up their efforts to better manage groundwater.

Groundwater makes up 99% of all liquid fresh water on Earth, underpinning its importance in providing drinking water to the world, sustaining food production, and maintaining healthy ecosystems. Many important global organizations have concluded that there is a freshwater crisis and given that nearly all freshwater is groundwater, the freshwater crisis is a groundwater crisis. During drought in many locales, groundwater is the only freshwater available, putting even more pressure on groundwater resources.

According to the World Health Organization and UNICEF (WHO/UNICEF, 2025↗), 2.1 billion people (1 in 4) live without safely managed drinking water and 3.4 billion people (4 in 10) live without safely managed sanitation. With groundwater directly supporting 8 of the 17 UN Sustainable Development Goals, groundwater is an invaluable resource. Safe and reliable access to groundwater directly supports the 2026 UN World Water Day (March 22) Theme "*Water and Gender Equality*" focusing on ensuring that women and girls have equal rights and leadership in water management.

The Groundwater Project (GW-Project), a registered Canadian charity founded in 2018, pioneers in advancing the understanding of groundwater by providing groundwater education to everyone. Recognizing that the world needs more highly skilled groundwater scientists to solve the water crisis, the GW-Project plays a pivotal role in creating the knowledge base for building the much-needed human capacity for the development and management of groundwater.

The GW-Project gained global recognition with publication of 64 original books, 94 translated books (in 59 languages), 7 interactive groundwater educational tools/modules, and over 50 high-quality educational videos, all made possible by a dedicated international group of over 1000 volunteer professionals from a broad range of disciplines throughout 70 countries on six continents. Academics, practitioners, and retirees contribute by writing and/or reviewing books aimed at diverse levels of readers including children, youth, undergraduate and graduate students, groundwater professionals, and the general public.

The GW-Project operates with the philosophy that high-quality groundwater education should be freely accessible for everyone, and to that end our publications are available free-of-charge on our website↗. We thank our corporate sponsors and private donors for making this possible. Please consider sponsoring the GW-Project so we can continue to provide groundwater education free of charge.

The Groundwater Project *Board of Directors*, January 2026

Foreword

In 1956, M. King Hubbert made a bold and controversial prediction: conventional oil production would peak between 1965 and 1970. At the time, few believed him—but history proved him correct -- but for only 47 years. Production peaked in 1970 in the United States and in 1974 in Canada, marking a turning point in the global energy landscape. Just a few years later, the 1973 oil crisis revealed how fragile that system truly was, as gasoline shortages spread and the world confronted the reality of limited supply.

For decades, conventional oil production in North America declined, reinforcing the idea that the era of abundant oil was fading. Then, unexpectedly, innovation reshaped the narrative. Advances in directional horizontal drilling and hydraulic fracturing—commonly known as fracking—unlocked vast reserves of unconventional oil and gas from low permeability shales. US oil production surged once again, and by 2017 had surpassed the 1970 production peak and is in 2026 roughly 30% higher.

Yet this progress has not come without consequence. Fracking requires large volumes of fresh water and use of hazardous chemicals. In some cases, it has been linked to induced earthquakes and increased methane emission. Indeed, every oil and gas well releases methane to the atmosphere—the only uncertainty is the extent of that leakage. These realities sparked ongoing debate, leading to bans and restrictions on unconventional oil and gas production in eastern Canada and many countries around the world.

This book, *Groundwater Contamination and Geoenvironmental Impacts of Upstream Oil and Gas Production* brings these critical issues into focus. With clarity and depth, it explores unconventional oil and gas extraction and its environmental implications, particularly through hydrogeological, geomechanical, and geochemical perspectives. As the second publication by the Groundwater Project on this topic—following *Groundwater and Petroleum*—this work builds on a strong foundation of research into the relationship between energy production and groundwater systems developed in the last twelve years.

Authored by a team of Canadian experts with international experience, this book reflects decades of research and professional insight into the deep subsurface environment. Their work spans critical areas such as radioactive waste repositories, subsurface carbon dioxide storage, and underground caverns for fluid storage. Together, they offer not only technical expertise but also a broader perspective on how we interact with—and impact—the hidden systems beneath the Earth's surface.

This is more than a scientific text. It is a call to understand the balance between innovation and responsibility—an invitation to look deeper, think critically, and engage with one of the most pressing environmental challenges of our time.

John Cherry, The Groundwater Project Leader

Guelph, Ontario, Canada, March 2026

Preface

Hydrogeologists and personnel in the oil and gas industry operate in different communities of practice and seldom interact. Investigations by hydrogeologists often identify and document cases of groundwater contamination caused by industrial activities such as those of the oil and gas industry.

In this century, the development of unconventional gas wells has led to considerable scrutiny of the industry by environmental regulators. Often, the problems identified, especially poorly completed oil and gas wells, have caused groundwater contamination directly by brine or natural gas, and gas emissions to the atmosphere. Furthermore, shallow aquifers penetrated by deep poorly completed wells have sometimes been cross contaminated by methane, causing sulfate reduction of the groundwater and thus subsequent groundwater contamination by reduced ions, e.g., iron, manganese, hydrogen sulfide, and a resulting absence of dissolved oxygen.

This monograph describes geoenvironmental issues, including groundwater contamination, that are important for hydrogeologists to consider when dealing with oil and gas operations, and addresses how these issues might be mitigated. In addition, it summarizes the extraordinary recent progress made since 2013 when a “lack of sound scientific hydrogeological field observations and a scarcity of published peer-reviewed articles on the effects of both conventional and unconventional oil and gas activities on shallow groundwater” was the subject of a critical review paper in the journal *Groundwater* (Jackson et al., 2013).

Executive Summary

The upstream sector (exploration and production) of the oil and gas industry has produced a vast literature on the exploration for and production of petroleum resources. However, some environmental concerns, including releases of greenhouse gases, were overlooked by various USA laws of the late twentieth century that gave exemptions to the petroleum industry. We address these concerns in this book, and we use the term "geoenvironmental" to identify not only issues of groundwater and soil contamination, but also broader environmental issues, such as how oil and gas developments have contributed to the release of greenhouse gases.

Section 2 of this book addresses the nature of oil and gas development including well construction and completion, which includes hydraulic fracture stimulation or *fracking*. We explain both the geochemical and geomechanical aspects of fracking so that hydrogeologists may appreciate that it is unlikely to be of serious concern for shallow groundwater. However, the plugging and abandonment of oil and gas wells has significant implications for hydrogeology and for climate change. We discuss these implications in detail.

Section 3 reviews the potential geoenvironmental pathways of contamination from oil and gas operations. Here, we are specifically concerned with contamination at the well pad. Regulatory issues also have a role in causing or preventing groundwater contamination; we therefore discuss the regulations that USA jurisdictions have enacted to enforce the shutting in of surface casing or wellhead vents and valves that may cause subsurface diversion of fugitive gases from the well. We also consider the necessary size of set-back distances from new oil and gas wells being fracked. Finally, we discuss why emissions of methane, other hydrocarbon gases, hydrogen sulfide and carbon dioxide from oil and gas wells are all sources of concern in the global management of greenhouse gases.

In Section 4, we turn to the forensic analyses of field studies of groundwater contamination and gas releases associated with oil and gas production. These field studies present case histories from well-pad activities, fugitive gas migration from leaky oil and gas wells, and evidence for the in-situ biodegradation of methane dissolved in groundwater. In addition, we discuss the rates of gas emissions around oil and gas wells, whether operating, suspended or abandoned, including wells that have been properly decommissioned.

Recent experimental field studies of fugitive gas migration are discussed in Section 5, whether in the shallow subsurface or from the greater depth of the reservoir. Here, we include an account of work done to estimate gas emissions from abandoned wells in Pennsylvania, where these techniques have passed from an experimental stage to operational use.

We end the book with an account of sampling and analysis methods for fugitive gases in groundwater and in atmospheric emissions (Section 6), including baseline groundwater quality monitoring, and with a review (Section 7) of numerical simulation studies to evaluate the risk of shallow groundwater contamination by fracking and by subsurface gas migration. We include discussion of the simulation of fracture propagation and the geomechanical stability of oil and gas wells.

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1 Introduction

The issue of groundwater contamination by the upstream[1] oil and gas industry came into public view around 2010, with the expansion of *fracking*[2] techniques for the development of unconventional (tight) oil and gas resources. This contamination often occurred in areas that lacked a long tradition of oil and gas development. The growth of public attention to methane leaks occurred in the decade following 2010, although it was preceded by several warnings from hydrogeologists working outside the petroleum industry.

One reason for this delay is that methane had not been considered a groundwater contaminant and low concentrations of methane in drinking water are not a concern for human health. However, the presence of methane in groundwater can be an indication of groundwater contamination by other hydrocarbons, including benzene, a known carcinogen. Dissolved methane can be released to the atmosphere when the water is pumped to the surface, and methane gas can migrate to the surface through preferential pathways and contribute to air quality degradation and climate change. Harrison (1985), Chafin (1994), and Van Stempvoort and others (2005) identified the hazards of methane releases from *poorly completed*[3] oil and gas (i.e., energy) wells in the contamination of shallow groundwater. For example, methane can reduce sulfate to hydrogen sulfide, significantly affecting groundwater quality.

The perceived problems with fracking caused public alarm in 2009-2010 with the development of the Marcellus Shale in Pennsylvania (USA) amid reports of water-well contamination and even well-vault explosions[4]. Initial studies detected deep thermogenic methane gas in the shallow bedrock and many inferred that fracking was to blame for groundwater contamination by methane and the associated alteration of water chemistry. However, as the early warnings from hydrogeologists pointed out, the source of local methane contamination was actually linked to the oil and gas wells drilled to access hydrocarbon resources, rather than the activity of fracking itself.

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[1] The oil and gas industry comprises three sectors: the *upstream* sector involving exploration and production, the *midstream* sector involving refining of fluids and pipeline transmission of oil, gas and petroleum products, and the *downstream* sector where refined products, such as natural gas, gasoline, and diesel fuel are shipped, stored and sold.

[2] Technically *hydraulic fracture stimulation*, i.e., the stimulation or enhancement of fluid (usually oil or gas) production by hydraulic fracturing within the target reservoir. It is italicized because it is part of the jargon of the industry.

[3] In the context of this chapter, *poor completion* indicates that the cementing of well casings to the borehole rock wall is deemed insufficient to ensure that annular gas flow between casing and rock would be negligible during production and after abandonment.

[4] Underground confined spaces built around a water well can unintentionally allow natural-gas accumulation and perhaps the ignition and explosion of the gas within the confined space.

The title of the first refereed journal article by a team at Duke University in a series on the effects of fracking was: *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing* (Osborn et al., 2011). It found a correlation between methane in domestic water wells and the distance to the nearest gas well. However, the Duke University team were careful not to directly implicate hydraulic fracturing as the cause.

Subsequently, an editorial by R.B. Jackson (2014) and research results from the Marcellus and Barnett Shale *plays*[5] (Darrah et al., 2014) indicated that poorly completed oil and gas wells likely caused the methane contamination and not hydraulic fracturing of deep shale-gas formations. After this, the research focus in North American hydrogeology shifted to understanding how poorly completed wells can indirectly contaminate groundwater and local streams (e.g., Dusseault et al., 2000; Brantley et al., 2014; Woda et al., 2018; Perra et al., 2022; Morais et al., 2024; and Bordeleau et al., 2024).

In addition to poorly completed hydrocarbon wells, it is probable that surface spills and seepage of fuel and other fluids from impoundments at well pads are causes of groundwater contamination from upstream oil and gas operations. Kang and others (2023) have noted that over four million Americans live within 1 km of a documented orphan well (i.e., an oil and gas well without an owner) and 35% of orphan wells are located within 1 km of a domestic water well. Proville and others (2022) determined that nearly 18 million people from marginalized groups in the USA lived near active oil and gas wells, e.g., in Los Angeles, California (Hispanic, Asian, Black), southwest Texas (Hispanic), Appalachian region (elderly Whites) and northwest New Mexico (Native Americans).

Although the association of natural gas and local water-well contamination became linked, at least in the public mind, with fracking in areas of North America where shale-gas development was occurring, these same areas were already well-known for the presence of natural gas in the shallow bedrock. These shallow natural gas occurrences are typically located hundreds of meters above the shale gas formations but are necessarily penetrated by production boreholes targeting the deeper shale gas. Oil and gas boreholes were often poorly completed in these shallow bedrock horizons allowing buoyant gas seepage along the annular space between casing and bedrock wall. Molofsky and others (2021) have presented a thorough review of the various processes they have observed and inferred from detailed field studies across the USA.

Methane is naturally present in shallow bedrock across North America, including Illinois, USA (Coleman et al., 1988), East Texas, USA (Grossman et al., 1989), the northern Appalachians which include Pennsylvania, USA (Baldassare et al., 2014), the St. Lawrence Lowlands in Québec, Canada (Lavoie et al., 2016), and Alberta, Canada (Humez, Mayer, Nightingale, Becker et al., 2016). In areas of natural gas development, the conflation of

[5] A *play* is group of oil or gas fields or prospects in the same region and controlled by the same geologic conditions.

naturally occurring methane with that caused by gas-well drilling, hydraulic fracture stimulation, and gas production led to enormous confusion because of an absence of pre-development groundwater quality investigations that included rigorous testing for natural gases. The natural gas industry had not been required to develop a formalized method for surveying and background testing of groundwater prior to the installation of oil and gas wells that were to be completed by fracking. It is here that hydrogeologists have made an important contribution, albeit somewhat after the fact.

This book stresses the potential for soil and groundwater contamination from two aspects of oil and gas exploration and production: (1) the potential contamination of shallow groundwater by surface activities around (and en route to) well pads; and (2) the potential contamination associated with leakage of *fugitive*[6] natural gas caused by poor wellbore completion or poor wellbore plugging and abandonment (P&A). We also consider the importance of ground-surface measurements made of gas emissions from oil and gas wells because, although not a strictly hydrogeological matter, such measurements indicate hydrocarbon wells that may be also contaminating water wells and require local groundwater quality testing. In brief, the issue we examine is geoenvironmental rather than just hydrogeological, hence the title of this monograph.

Section 2 of this book provides a brief discussion of the upstream oil and gas operations as shown in Figure 1, focusing on hydraulic fracturing operations, and also includes plugging and abandonment practices. Section 3 addresses contamination, including the precautions taken by operators and how the precautions sometimes fail to prevent groundwater contamination, and ends with a discussion of two regulatory issues of consequence: (1) surface casing venting and (2) the establishment of set-back distances from energy-well drilling sites. Section 4 contains a review of the potential for and evidence of groundwater contamination and surface emissions. We examine several recent experimental field studies of gas migration (Section 5), which clarify the origin of groundwater contamination. In Section 6, we review methods of groundwater quality monitoring. Finally, numerical simulations of gas migration are discussed, highlighting especially those involving two-phase flow simulations and biodegradation of methane in groundwater (Section 7).

[6] *Fugitive* or *stray gas* refers to natural gas, predominantly methane, that has been released into or from the subsurface from oil and gas wells. We prefer to use the term *fugitive gas* because it implies the gas is mobile due to its buoyancy or pressure drive, while stray gas has no such connotation.

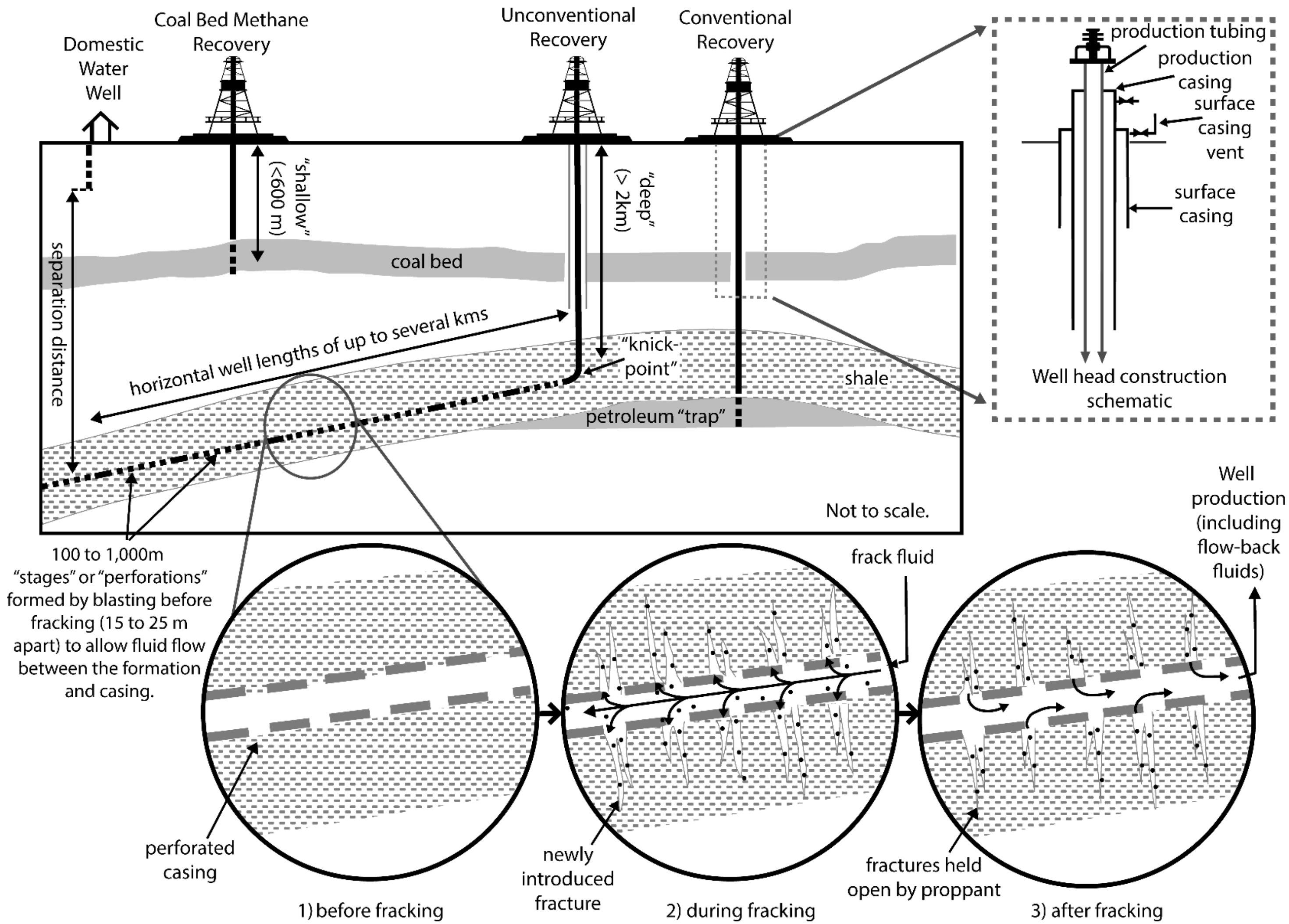


Figure 1 - Upstream oil and gas operations showing target horizons and casings for coal-bed methane, unconventional, and conventional resource recovery. Unconventional recovery often involves non-vertical wells. Insets illustrate 1) perforated casing, 2) conditions during hydraulic fracking, and 3) after fracking (prepared by Cathy Ryan, University of Calgary for Jackson et al., 2013).

2 Upstream Oil and Gas Operations in the Subsurface

Petroleum reservoirs occur in subsurface formations where oil and gas are present and accessible in commercial quantities. The geology of such reservoirs is quite variable and is beyond the scope of this book[7]. Rather, we consider the operational practices of exploration and production with emphasis on industrial activities that may contribute to groundwater contamination and atmospheric emissions. The text of this section is deliberately detailed to introduce hydrogeologists to exploration and production practices. Currently, such practices are often directed at low permeability reservoirs, such as shales, because the higher permeability reservoirs, particularly in North America and Europe, were largely discovered and depleted during the twentieth century.

Exploration and production terminology is defined and indicated by italics upon first appearance, and many of these terms are included in the Glossary provided in Section 13. To understand groundwater and surficial contamination resulting from oil and gas production, the reader must understand certain basic terms and techniques—introduced in this book—that are widely used in the exploration and production sector of the oil and gas industry, e.g., the term *play* is defined in footnote 5 on page 2. The interested reader may want to use the *Schlumberger Oilfield Glossary* (SLB Energy Glossary↗) for further definition of terms.

We begin this section by describing the construction of an oil or gas production well. We then consider hydrocarbon production and how such activities may contribute to groundwater contamination, followed by consideration of the stimulation of low-permeability reservoirs by hydraulic fracturing, more commonly known as fracking. We consider the causes of gas leakage that result in fugitive (i.e., unintended) gas migration and the regulations concerning the operation of surface casing vents and set-back distances during drilling and completion of a production well. Finally, we discuss the problems associated with plugging and abandonment of hydrocarbon wellbores and how they have been found to cause groundwater contamination.

2.1 Oil and Gas Well Construction

Figure 2 illustrates the main features of modern oil and gas well construction and completion. First, a vertical well is drilled to a depth of perhaps several hundred meters to install a fully cemented surface casing that protects shallow potable groundwater and surficial aquifers; the depth of shallow groundwater to be protected may depend on the definition of fresh water in the jurisdiction where the well is drilled (Kang & Jackson, 2016; Kang et al., 2020). After the surface casing has been installed, vertical drilling continues,

[7] Modern petroleum geology texts such as those by Selley and Sonnenberg (2014) or Bjørlykke (2010) provide more information.

and the borehole will often be gradually deviated to become a horizontal or inclined well. One or several additional steel casings will be installed and cemented in place during this operation.

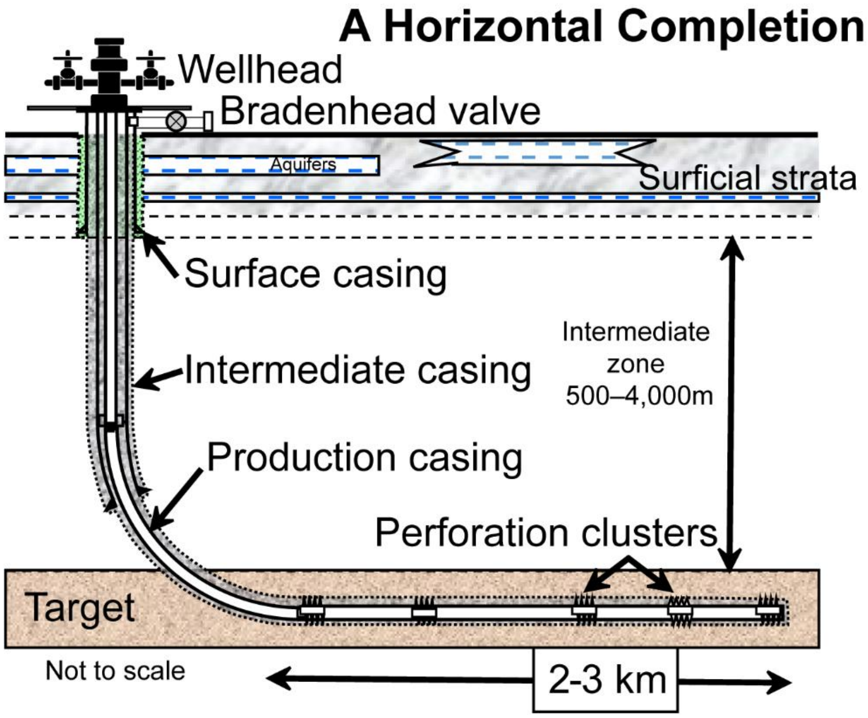


Figure 2 - A schematic construction diagram for an unconventional gas well. The brown zone labeled "Target" refers to the target reservoir formation. The horizontal black dashed lines indicate that the surface casing penetrates some distance into the intermediate zone to ensure a good seal. A Bradenhead valve is a valve on the annulus between the surface casing and the intermediate casing. The dashed line along the well is the drilled borehole wall; the borehole diameter depends on the diameter of the outermost casing. The dashed lines indicate freshwater aquifers (in blue) in the surficial strata and the uppermost part of the intermediate zone (in black) that may contain non-commercial volumes of gas.

In North America and elsewhere, oil and gas wells are now routinely drilled to allow a 1 to 3 km long horizontal or inclined leg of the well to be installed parallel to the bedding planes of the target reservoir formation, to extract the target hydrocarbons more efficiently. This approach permits the drilling of multiple wells from a single pad, with the horizontal sections of the wells installed in different directions, and greatly reduces the surface impact of oil and gas development, compared to the traditional approach of one vertical well per pad as shown in Figure 1.

The process of cementing the wellbore annulus to prevent cross-formational migration of gas and other fluids outside the casing is known as *primary cementing* (Nelson, 2012). With conventional cementing down casing, which involves pumping cement grout to the bottom of the drill string where the grout then flows up around the outside of the casing, (as opposed to inner string or reverse cementing), the cementing process proceeds as shown in Figure 3. First, before pumping down cement, a clean-up fluid and a spacer fluid are pumped into the casing, then a *wiper plug* (i.e., bottom plug) is installed within the casing. This plug travels in front of the cement — cleaning the inside of the casing—and prevents the cement from mixing with fluid that is already inside the casing. Behind the bottom plug, the cement slurry flows down inside the casing (Figure 3a). When the appropriate volume of cement has been placed into the wellbore—the volume calculated to fill the annulus, with some margin of error—an upper (top) wiper plug is placed in the casing behind (i.e., on top of) the cement and water is pumped into the hole to displace cement from the inside of the casing (Figure 3b). When the bottom plug reaches the bottom of the casing, it opens thus allowing the cement slurry to flow through it and up into the exterior annulus.

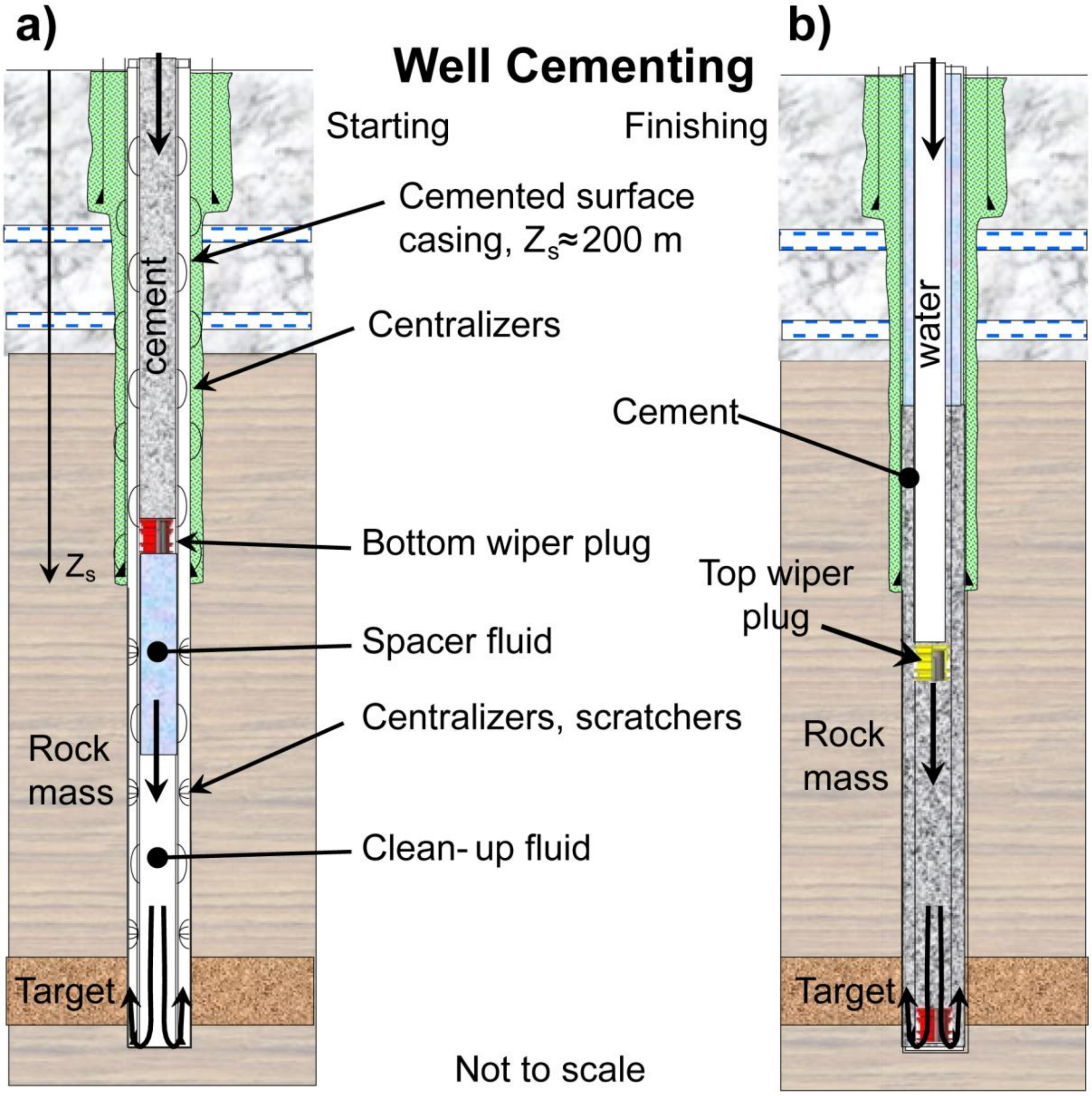


Figure 3 - Well Cementing: a) Cement is pumped down the production casing behind clean-up fluid and spacer fluid. Fluids flow up the annulus of the wellbore and displace the residual drilling mud. This is best accomplished when the casing is centralized within the borehole which is achieved by the use of centralizers. b) After the cement reaches the well bottom, it flows up the annulus to block gas migration from both the target reservoir and shallower gas-rich formations that would otherwise leak up an uncemented annulus. The horizontal strata with blue dashed lines represent shallow aquifers. The text provides more detail.

Finally, when the top plug reaches the bottom of the hole this will be indicated by an increase in pump pressure, which signals to the operator that cementing is complete. Typically, some cement returns out the top of the annulus confirming that cement fills the entire annulus, although this requirement varies by jurisdiction. The cement is allowed to set, creating a seal to prevent fluid flow between the formations penetrated by the well, which is referred to as *zonal isolation*. The cement also protects the casing from corrosion and increases its mechanical stability.

If primary cementing operations are done correctly the first time, there is a high probability that there will be limited or no gas migration in the annular region between the casing and borehole wall and thus no *wellbore leakage*. The operations shown in Figure 3 also accomplish the necessary step of removing *drilling mud*[8], which is the fluid circulated during drilling to cool the drilling bit, counter the downhole formation pressure, and lift the rock cuttings to the surface. Figure 4 shows results of an experiment that resulted in a poorly-sealed annulus between the production casing (represented by the outer plastic pipe) and the borehole wall (represented by the inner pipe), caused by poor drilling and cementing practice.

Figure 4 - Cement and drilling fluid channels resulting from incomplete drilling mud displacement because the casings are eccentrically aligned rather than being in concentric alignment. Therefore, the severity of the drilling-mud problem on the thinner part of the annulus is much greater than in the wider part (modified from Watson et al., 2002).

[8] *Drilling mud* refers to the fluid circulated through the drill string and wellbore during rotary drilling to cool and lubricate the drill bit and carry rock cuttings and fines out of the hole. Drilling mud may be formulated to control pressure in the well, to inhibit formation fluid (water, gas, oil) from flowing into the well, and to stabilize the exposed rock of the wellbore walls. Drilling mud may be water-based (including brine), oil-based, or synthetic oil-based. Additives may include materials such as bentonite clay or barite ($BaSO_4$) in a slurry, hence the name *mud*.

The completed well is shown in Figure 5 and Figure 6. The *production tubing* is a non-cemented string of pipes through which oil or gas is produced and is hung within the production casing.

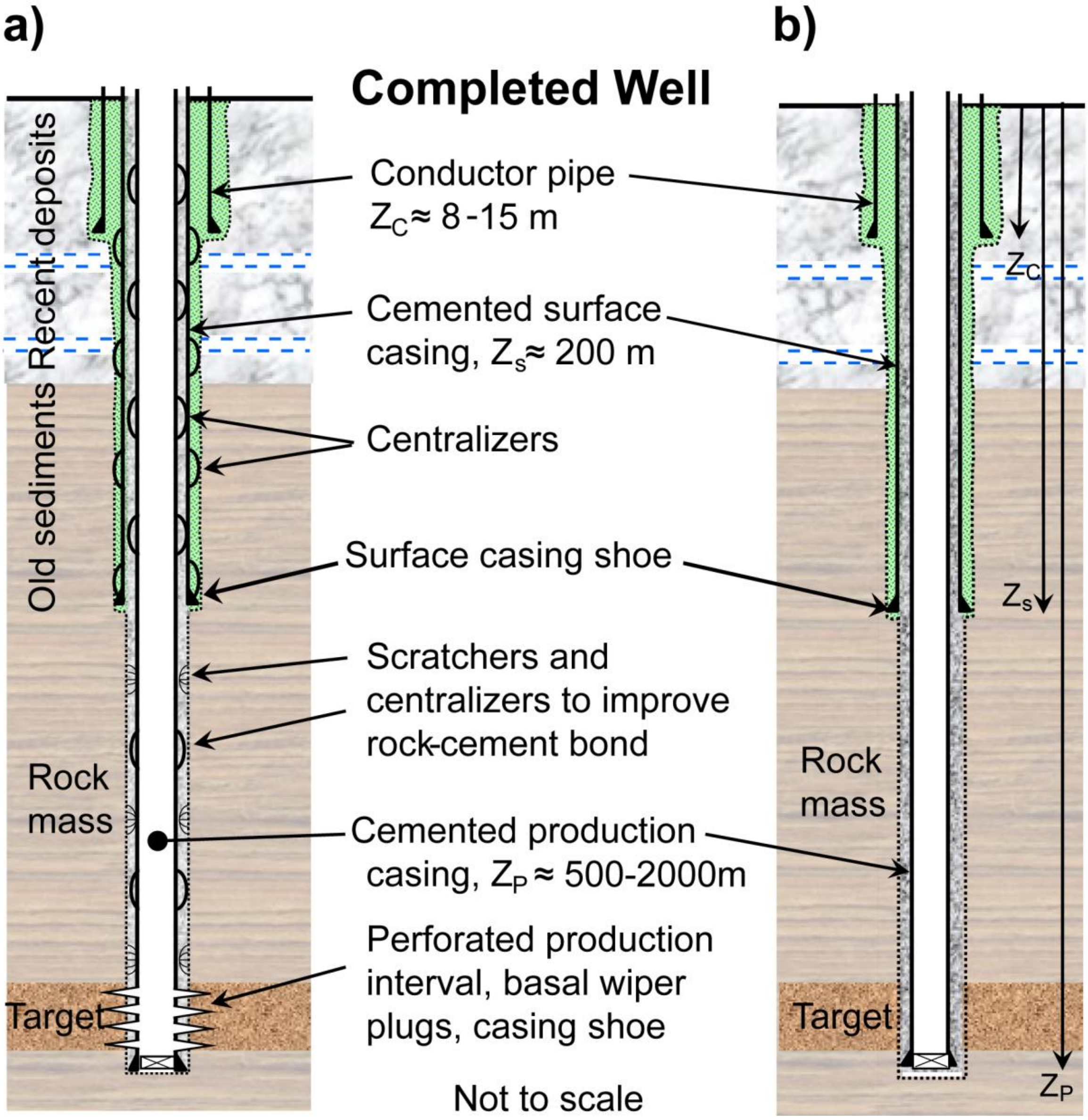


Figure 5 - a) Completed well showing selected well components, including centralizers behind the intermediate and production casings and components at and below the target reservoir. b) Typical depths of individual casings (Z_C, Z_S, Z_P) are shown. The horizontal strata with blue dashed lines represent shallow aquifers. The casing shoes are steel collars affixed to the bottom of the casings.

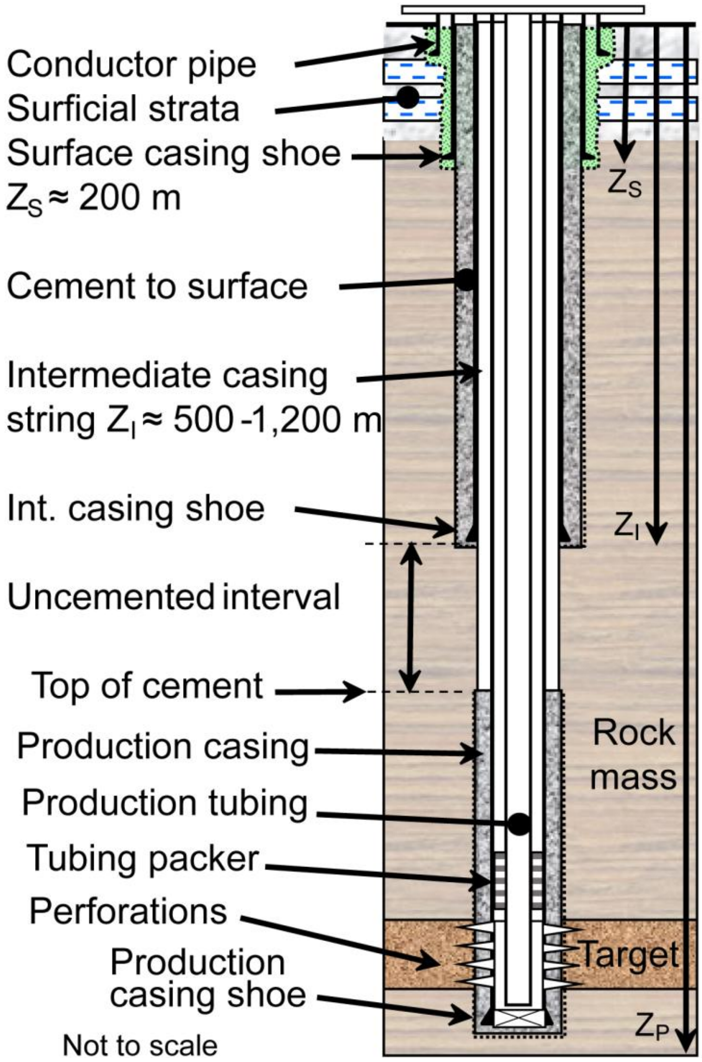


Figure 6 - Final construction diagram indicating various casings, cemented intervals, typical uncemented interval, casing shoes and perforated production interval at target depth with tubing packer.

As early as the 1970s, improved wellbore construction practices were identified as a means of reducing the rates and occurrences of wellbore leakage. Several mechanisms that might prompt the development of leakage sources and pathways were identified, including (Cooke et al., 1983 and references therein; Watson et al., 2002) as follows.

- Inadequate drilling mud removal (e.g., Figure 4).
- Failure to use centralizers in installing the production casing (which may result in poor mud removal as in Figure 4).
- Cement sheath failure leading to sheath cracking. This may be caused by cement quality problems leading to excessive shrinkage during set, or thermal stresses leading to cement or shale dehydration. Drilling ahead, perforating, or performing stimulation treatments such as hydraulic fracturing too soon after a well is cemented may also cause cement sheath failure.

- Casing couplings and threads that, while suitable for vertical wells, are inadequate for the deviated and extended horizontal sections of more modern wells.
- Autogenous cement shrinkage during cement setting creating a *micro-annulus* or *micro-annuli*, which are millimeter or sub-millimeter sized channels that permit gas flow in the annulus behind the casing (Alberdi-Pagola & Fischer, 2023b).
- Gas migration into the still-liquid cement during setting, creating an open channel.
- Absence of cement protecting the casing, referred to as *low cement top*, i.e., the cement column is insufficient to cover and thus protect the full height of the casing.

2.2 Hydraulic Fracturing Operations

The controversy surrounding groundwater contamination and methane emissions in upstream oil and gas activity is closely connected to the proliferation of fracking, or hydraulic fracture stimulation, for development of unconventional hydrocarbon resources. Although fracking has been performed in vertical wells using a wide range of methods, including dynamite in the nineteenth and early twentieth century, our focus is on modern fracking operations employing staged, high-volume, high-pressure fluid injection for the stimulation of long horizontal well sections.

Stimulation of unconventional oil or gas wells through hydraulic fracturing, as shown in Figure 1, is now normally done in horizontal boreholes. Fractures are generated sequentially along the length of the borehole, from the toe (bottom of well) to the heel (point at which the horizontal leg of the well begins), with one interval, or *stage,* after another being isolated and fractured using a high-pressure, usually water-based, fluid. The injected fluid may include (i) gelling agents that allow the generation of a fluid with viscosity to carry proppant, (ii) biocides to prevent fouling of the well through biodegradation of the organic gelling agent, (iii) sand, or ceramic *proppants,* to hold the fractures open so that oil and/or gas may later escape, (iv) friction-reducing acrylamide polymers in *slickwater* fracturing, and (v) other chemicals to facilitate the process. These other chemicals, usually present in small amounts, may include cross-linking agents to enhance the viscosity effect of the gel, corrosion inhibitors, oxygen scavenging agents, scale inhibitors, potassium chloride to reduce shale swelling, viscosity breakers to aid in de-polymerizing gels once the pumping ceases, and fluid loss control agents such as finely ground graphite or calcium carbonate, $CaCO_3$.

A broad review of hydraulic fracturing technology is provided by King (2012). The well is considered *completed* when the horizontal leg of the well has been perforated (if necessary), then stimulated or fracked, to allow the formation fluids to flow into the wellbore. At this point, the well is ready for production.

The process described above is referred to as *multi-stage hydraulic fracturing*. Such stimulation operations, as shown in Figure 7 and Figure 8, are conducted within a horizontal well. The critical aspect of this approach is to maximize the extent to which each single well can access the formation containing the hydrocarbon resource. Thus, it is cost effective to undertake several fracking stages along the length of the horizontal leg, which is typically from 1.5 to 3 km in length. As drilling and completion technology improves, longer horizontal sections (e.g., 3 km) are becoming more common.

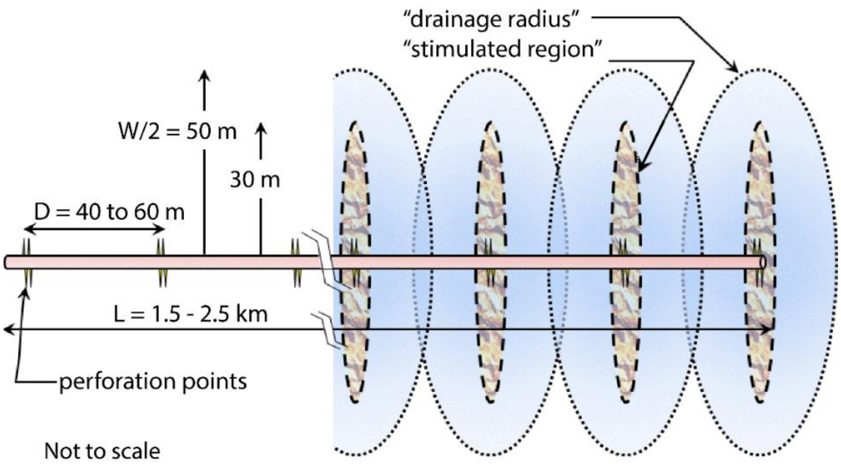


Figure 7 - Plan view showing the concepts and typical dimensions of a stimulated region and a drained volume surrounding a single horizontal well positioned 100 m laterally from an adjacent well (i.e., W = 100 m). D is the distance between well perforations along the well casing and L is the length of the horizontal leg.

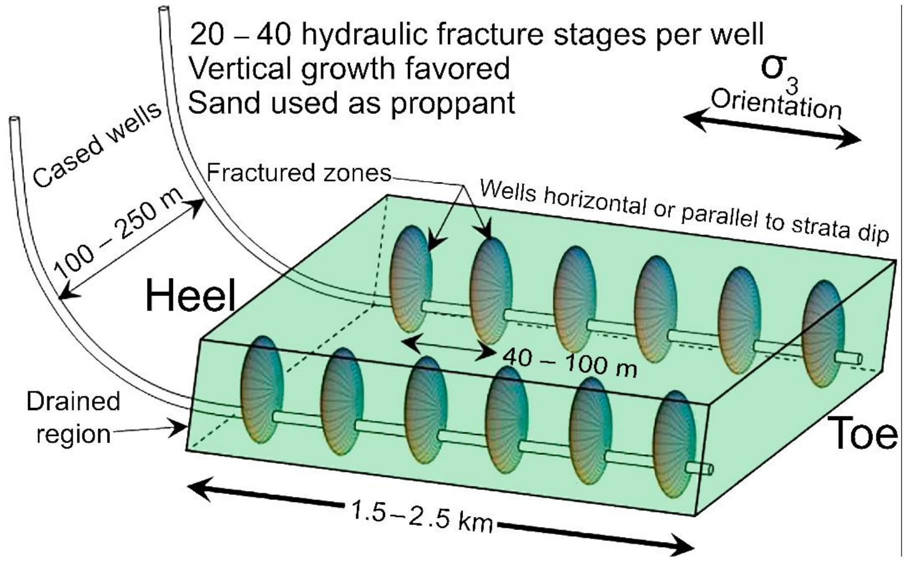


Figure 8 - Configuration of multi-stage hydraulic fracturing wells within the target formation. Fractures propagate perpendicular to the direction of the minimum principal stress in the formation, σ_3.

In some cases, the horizontal section may be cased and cemented, usually to guarantee borehole stability; then, the steel casing and cement must be perforated to access the formation. The method is referred to as *plug-and-perf*: an interval in the closed steel casing is isolated by two packers so that the casing may be perforated and therefore allow the hydraulic fracturing fluids, including the sand particles (*proppant*) used to prop open the new fractures, to be injected into only one zone. The method of perforation is to detonate explosive shaped charges, deployed in a "perforating gun". Abrasive jetting or high-pressure fluid jetting may also be used to create perforations.

Horizontal boreholes for shale gas exploitation are typically 500 to 4500 m deep. Even within a play there will be a range of depths because of gradually dipping formations within a sedimentary basin. The Marcellus Shale is close to 3 km deep in the southeastern part of the play in central Pennsylvania, USA, but only a kilometer deep in the northwestern part of the play in Ohio, USA. In a few cases, the depth to the horizontal wellbore could potentially be as shallow as 300 m, as in the coal bed methane play (e.g., Figure 1) in central Alberta, Canada before 2010, or as much as 4500 m in the deeper shale gas wells in northeastern British Columbia, Canada in the Horn River and Liard plays.

2.2.1 Flowback and Produced Water

As the pressure in the well drops after hydraulic fracture stimulation, a portion of the fracturing fluid (~25%; Haluszczak et al., 2013) will flow back to the well. This is known as *flowback*; because this wastewater will contain many of the components injected into the target formation, it may be hazardous. The geochemical composition of flowback fluids from the Marcellus shale-gas play in Pennsylvania has been described by Ferrar and others (2013), Haluszczak and others (2013), Engle and Rowan (2014), Warner and others (2014). Bibby and others (2013) developed a list of recommended reporting parameters for flowback fluids. The data of Haluszczak and others (2013) are summarized in Table 1. Additionally, if there is mobile water in the producing formation, some of this water will be co-produced along with the oil and gas, and this is called *produced water*. Produced water is primarily natural formation brine with very high total dissolved solid (TDS) concentrations and, in some circumstances, substantial concentrations of toxic metals such as barium and radium. Produced water is discussed in the freely downloadable Groundwater Project book *Groundwater and Petroleum*↗ (Kharaka et al., (2024).

Table 1 - Median concentrations of the major components of injected fracking fluid and flowback water from seven horizontal wells, Marcellus Shale play, Pennsylvania, USA (Haluszczak et al., 2013).

Parameter	**Median concentration in injected fluid in mg/L**	**Median concentration in flowback fluid in mg/L**
pH	7.0	7.2
Alkalinity ($CaCO_3$)	126	71
TDS	735	157,000
Total Organic Carbon (C)	205	14
Chloride	82	98,300
Calcium	32	11,200
Sodium	80	36,400
Barium	0.6	1990

Maloney and Yoxtheimer (2012) summarized the production of waste materials from the Marcellus Shale play and noted it was necessary for much waste to leave Pennsylvania, USA for final disposal. Waste treatment and disposal thus represent a challenge for any region that lacks adequate infrastructure for disposal, and raises the risks associated with the transshipment of waste materials, because handling, transportation, and re-handling substantially increase the chance of a spill or other release to the environment. In addition, disposal of large volumes of produced water by injection in deep formations has induced seismic activity in Oklahoma and elsewhere (Ellsworth, 2013).

Alessi and others (2017) examined the sources of hydraulic fracturing water for the Marcellus and Barnett plays in the USA and the Montney and Duvernay plays in western Canada. They also considered the produced wastewater, their methods of treatment, reuse or disposal, and how these practices varied across the four unconventional shale gas plays. Generally, the wastewater was operationally defined as combined flowback, produced and maintenance water. The largest volume of wastewaters was flowback and produced water that were returned to the surface following reservoir stimulation.

2.2.2 Fracture Propagation

In any body of rock in the subsurface, there exists a state of stress, which is generally defined according to three perpendicular compressive stresses, the so-called principal stresses (Zoback, 2010). Due to the weight of overlying rock (gravity), one of these principal stresses is usually the vertical stress (σ_V). The other two principal stresses are the minimum and maximum horizontal principal stresses, respectively denoted σ_h and σ_H. Hydraulic fracture propagation is dominated by the orientation of the minimum principal stress, which may be σ_V or σ_h, and is normally denoted σ_3. Induced fractures typically propagate normal to σ_3 because of work minimization. Simply stated, $Work = Force\ (displacement) = \sigma A d$, where σ represents the stress normal to the fracture plane, A is the fracture plane area, and d is the mean induced aperture of the hydraulic fracture. Work minimization principles lead to the conclusion that the fracture opening stress must be $\sigma \approx \sigma_3$, and this is invariably confirmed by measurements. In other words, it requires less energy to open a fracture perpendicular to a lower stress.

In many sedimentary basins the minimum principal stress in the target hydrocarbon-bearing formation, or *pay zone*, is horizontal, leading to vertical propagation of stimulated fractures. Vertical hydraulically induced fractures will usually propagate a significant distance above the horizontal borehole (Davies et al., 2012; Fisher & Warpinski, 2012; Warpinski & Teufel, 1987) because the treatment fluid is buoyant in the stress field, but there have been no observed cases where assumed vertical fracture propagation exceeded 600 m. Usually these induced fractures terminate far below the lowest elevation of potable groundwater.

In addition, this estimated maximum propagation height of 600 m is based on microseismic emissions analysis, and it is known that microseismic emissions take place not only in the vicinity of the hydraulic fracture itself (the opened fracture), but usually far in advance of the propagating fracture (Warpinski, 2014). This is because strain propagation from the distortion generated by fracturing propagates far beyond the actual fracture opening, and because the high fracturing pressures create a diffusion-rate-controlled pressure wave that also travels well in advance of the pressurized crack. These more distant strains and pressure changes trigger a cloud of small stick-slip events on weak planar features (such as bedding planes, joints) within which the hydraulic fracture resides (Warpinski, 2014), and induced microseismic events 100 m or more above the actual fracture are common.

There are several processes which limit the vertical propagation of hydraulic fractures. First, the volume of water used for a hydraulic fracture stimulation is designed to fracture only the target formation. As an example, in the Horn River play in northeastern British Columbia, Canada, the substantial reservoir thickness means that a large volume of fracture fluid is used in each stage, perhaps as much as 3500 m^3; these are among the largest per-fracture treatment volumes in the world. In the Marcellus Formation in Pennsylvania, USA, however, injection volume per stage is much smaller, on the order of a few hundred m^3, because the formation is thin (40 to 50 m) and because there appears to be no strong barrier to upward hydraulic fracture propagation at the top of the shale gas interval. There is no incentive for operators to fracture formations out of the *pay zone*. On the contrary, it is desirable to keep fractures from propagating excessively above the top of the productive horizon, simply because it is a waste of money to inject fluids that do not aid production. Most of the injected fracking fluid is not recovered as flowback fluid; evidence indicates that it imbibes into the shale matrix (Engelder et al., 2014).

Crustal stress fields also tend to limit vertical propagation. In most continental jurisdictions, the sedimentary basins have experienced erosion, leading to a condition where the upper strata (generally, the upper several hundred meters) are in a *thrust fault* stress state in which the vertical stress, σ_V, is the minimum principal stress, i.e., $\sigma_V = \sigma_3$ (World Stress Map Project↗; Tingay et al., 2005; Zoback, 1992). Vertically propagating fractures will turn and start propagating horizontally when σ_V becomes σ_3. Figure 9 shows a measured stress state in southeastern Alberta, Canada (Milk River Formation, approximately 110°W, 51°N), showing that above a depth of about 370 m, σ_V is the minimum principal stress. Typically, hydraulically induced fractures will rise vertically, but once above a depth of about 350 m, they tend to re-orient to become horizontal, and propagate roughly parallel to the earth's surface, usually parallel to bedding in the undeformed sediments. This propagation orientation change with depth was confirmed by flow tests in the shallow exploited Alberta gas fields (Nadeem & Dusseault 2013). This change in stress orientation is widely observed, and it means that the possibility of a hydraulic fracture propagating to the surface even if initiated at relatively shallow depth is remote. Only water wells intercepted by such induced horizontal fractures are susceptible to their effects; such problems may have occurred in Alberta when the exceptionally shallow coal-bed methane play was in production before 2010 (Jackson et al., 2015; Tilley & Muehlenbachs, 2012).

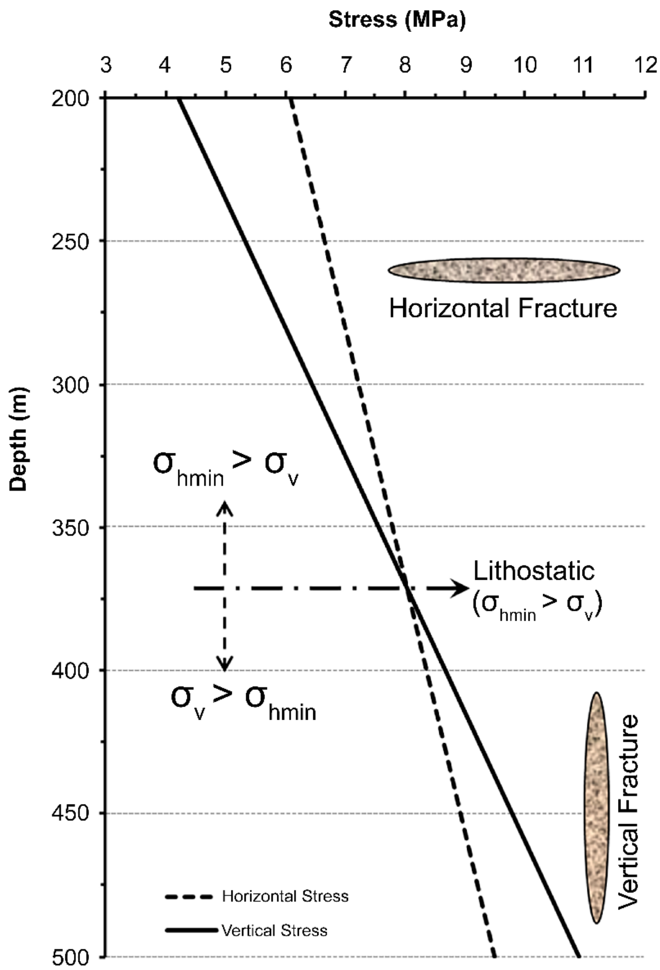


Figure 9 - Stress state measured in the Milk River Formation shallow gas play in southeast Alberta, Canada. Calculated stress profile of the study area showing conditions between 200 m and 500 m depth. Above the critical depth of 370 m, induced hydraulic fractures will likely have horizontal orientation whereas below that depth they will likely be vertical (adapted from Nadeem & Dusseault, 2013).

Optimum placement of a wellbore within a formation depends on factors such as the orientation and magnitude of the stresses, the nature of the hydraulic fracturing fluids to be used (density, viscosity), as well as the injection pressure and rate to be used in stimulation. The stimulation size (volume) at each perforated stage along the axis of the well, and the spacing between stages, are optimized during the early development stages when pilot hydraulic fracturing in horizontal wells is conducted (Mayerhofer et al., 2010). The plan view shown in Figure 8 is a possible multi-stage hydraulic fracturing approach with horizontal wells spaced 100 to 250 m apart laterally. Figure 7 shows the concepts of a stimulated region directly affected by the fracturing operation and a drained region that is much larger. When the formation permeability is low, stimulation will generate small perturbations beyond the region of the induced fracture network and the zone within which the fractures are propped open. Over the life of the well, the volume within the drainage radius, which is larger than the fractured zone, will contribute to production.

In Figure 7, it is assumed that the stimulated zone limit is about 50 m on either side of the wellbore, which is a realistic scenario for a target reservoir that is 35 to 75 m thick. The fractured zones themselves do not overlap, but the drainage regions overlap slightly. Quantification of these aspects for optimization can only be achieved by monitoring production trials that are subsequently modeled using geomechanically coupled flow simulators.

At depth, adjacent wells might be configured as shown in Figure 8. In this representation, only six fracture stages along the axis of each horizontal well section are shown for artistic purposes. The fracture stimulated zone is represented by the ellipsoids, and the more extensive drainage volume is schematically depicted. The two wells shown in Figure 8 would be drilled from the same pad, along with many other wells. This is possible due to advances made in the directional drilling of wells in the 1990s, such as the use of downhole drilling motors (mud motors) and data transmission to the surface while drilling to allow steering of the drill bit as it cuts through the rock.

Finally, hydraulic fracturing stimulation, when conducted in structurally deformed regions or areas where in-situ stresses are close to a critical slip condition (as discussed by Zoback, 2010, chapter 11), may result in lateral pore-pressure transmission to nearby stressed faults, with subsequent seismic slip causing minor earthquakes (Ellsworth, 2013; Frohlich & Potter, 2013; Skoumal et al., 2015). The process of stimulation has occasionally led to human-felt earthquakes in the Western Canada Sedimentary Basin of British Columbia and Alberta, usually less than magnitude 4, i.e., M4 (Farahbod et al., 2015). However, several induced earthquakes that exceeded M4 (Atkinson et al., 2020) have been registered in northwest Alberta and northeast British Columbia during stimulation operations.

2.3 Plugging and Abandonment

Oil and gas wells that have been plugged and abandoned in modern times use contemporary methods of abandonment including balanced cement plugs, cast iron and elastomer bridge plugs, and dump-bailed cement plugs, all of which are plugs of cement, rubber, or metal to prevent leakage from inside the well to the ground surface or shallower formations. Wells abandoned before the 1950s (USA) or the 1970s (Canada) are considered *legacy* abandoned wellbores. These abandoned wellbores must be considered separately from modern abandoned wells.

2.3.1 Historical Practices in Legacy Wells

When oil and gas drilling began in the mid-nineteenth century, there was no regulation regarding abandonment of a well at the end of its production, and operators could simply walk away from an open hole in the ground. In the 1890s plugging and abandonment regulations were instituted in some jurisdictions, with the primary goal of protecting production zones from flooding by water and "conserving" the reservoir. It wasn't until the 1920s that multiple cement types became available for plugging wellbores, followed by: the development of centralizers in the 1930s (as shown in Figure 3 and Figure 5); further developments of Portland cement with additives; the introduction of calipers in the 1940s to measure the inside diameter of an open borehole or tubing; and the publication of American Petroleum Industry standards for wellbore cements in 1953 (Benedictus, 2009).

Wellbores abandoned prior to 1950s in the USA (Dilmore et al., 2015) and 1960–1970s in Canada are now considered to be inappropriately abandoned (NPC, 2011), and the same consideration applies in other jurisdictions. Typically, earlier plugging operations were designed to prevent the loss of oil and gas to other formations to protect the resource, not the environment. In the USA, early regulations enabled wells to be plugged with "brush, wood, rocks, paper and linen sacks, or a variety of other handy items that would serve to hold a sack of cement" (NPC, 2011, p. 7), which is consistent with anecdotal information regarding re-abandonment operations on wells drilled before 1970 in North America. As regulations improved, cement became a required material for sealing the producing intervals and the top of the wellbore. Over time, plugging regulations have progressed to prescribe the specific intervals at which cement should be placed and the types of materials allowed between the cement plugs. According to NPC (2011), the basic technology associated with the plugging and abandoning of wells has not changed significantly since the 1970s.

Well abandonments before the 1970s, particularly during World War II, were much more rudimentary than what is now considered necessary. Legacy abandoned wells—of the kind shown schematically in Figure 10—may feature the following.

- **Missing casing** – Wherever possible, the casing was pulled upon abandonment, potentially due to the high value of steel during World War II. The fact that it was possible to pull the casing implies that the exterior annulus was not cemented and was probably filled with drilling fluid. In some cases, a portion of the casing could not be removed and was left in the hole.

- **Wooden plugs** – Materials described as wooden plugs, wooden mandrels, spruce logs, etc. were used as bridge plugs (mechanical plugs providing a solid seal installed in an open hole) during abandonment of many wells. The operators describe driving the plugs tightly into the hole, presumably using a drill string or a wireline anvil.
- **Cement** – In some cases, well logs would include a note along the lines of *a few bags of neat cement were placed on top of the bridge plug*. Neat cement is a term of practice identifying a mixture of Portland cement powder and water, in which the ratio is carefully controlled.
- **Stone** – Sometimes, stone (coarse gravel size) was also installed on top of the plug, perhaps to counteract buoyant uplift of a wooden plug.
- **Sand** – In many abandoned wells, a large fraction of the wellbore was filled with pumped sand occupying the space above and between bridge plugs.

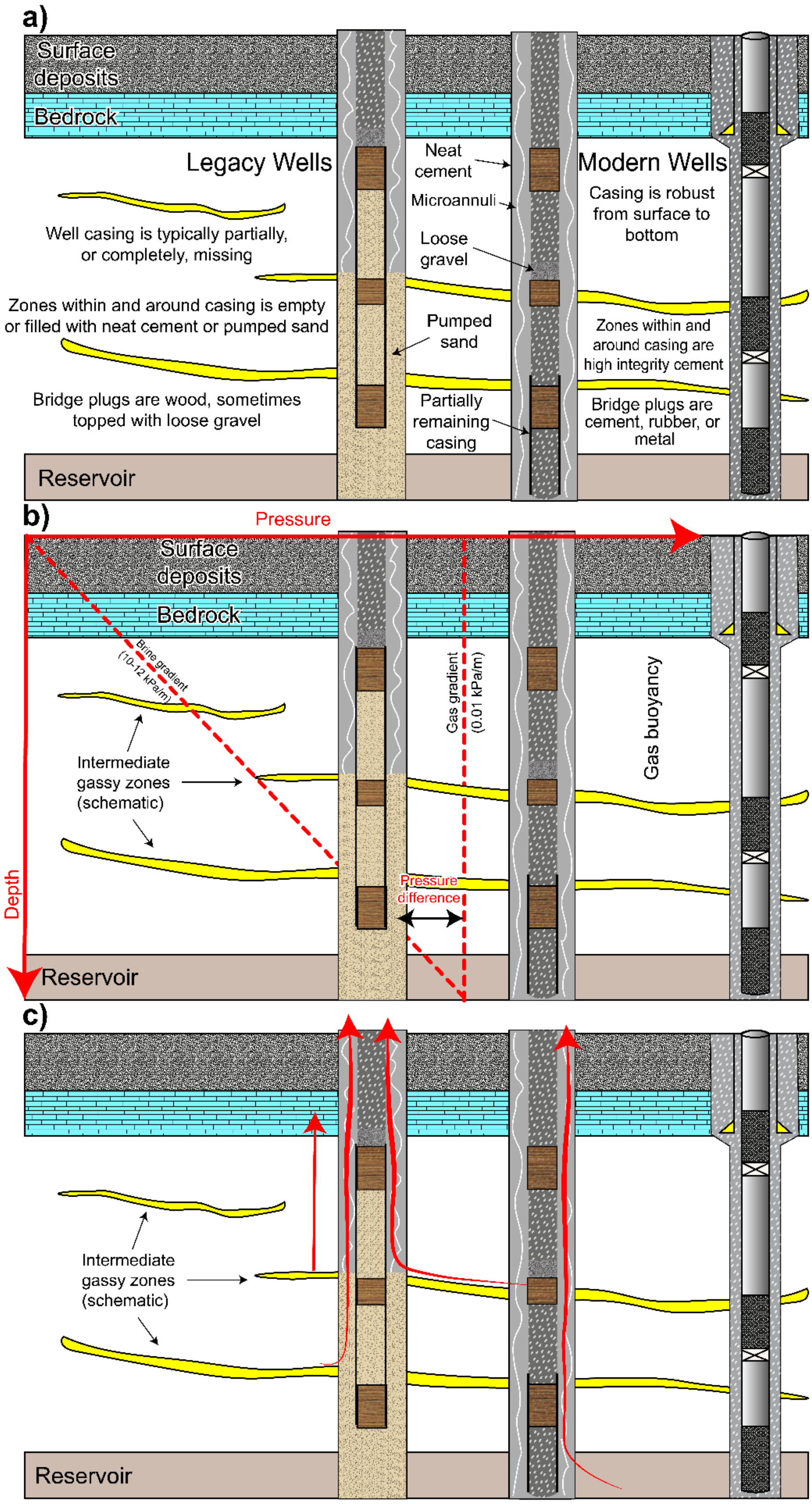


Figure 10 - a) Some differences in abandonment methods between legacy wells and a modern well. b) Pressures in brine and gas. c) Buoyant gas flow develops in legacy wells along unsealed pathways because of the pressure difference generated between brine and gas. Modern well abandonment is discussed in Section 2.3.3.

The buoyancy of natural gas leads to vertical gas migration, causing a pressure difference generated between brine in the formation and the gas (Figure 10). Old oil and gas fields host thousands of poorly abandoned and leaky wells such as those shown in Figure 11 , and these wells may develop surface emissions many decades after abandonment. The wells pose significant technical and financial problems to jurisdictions because the cost of modern plugging and abandonment must be borne by the responsible government, i.e., the taxpayer. In old fields, such as Ontario, Canada, there are limited revenues being returned to the government as petroleum royalties because production from the depleted reservoirs is greatly diminished or totally absent. However, even in production areas that are active in the present day in Alberta, Canada in year 2025—the financial needs of orphan well programs are believed to greatly exceed the revenues available to these programs.

Figure 11 - a) View from above a poorly abandoned well discharging ~3 L/s of water under artesian pressure in 2019, Norfolk County, Ontario. No surface casing was left in-situ. Both methane and hydrogen sulfide were measured at the ground surface in early 2021. b) Salt precipitates deposited by discharge from the well shown in (a). c) Discharge in March 2022 following the development of a sinkhole during a period of high artesian discharge (photos courtesy of Colby Steelman and Brian Craig, University of Waterloo).

Legacy wells are poorly documented and leave much of the information needed for their remediation is not available. Figure 12 illustrates typical abandonment notes from 1941 for a well in the Stoney Creek oilfield in New Brunswick, Canada. These notes read as follows.

> *"Pulled 5 3/16" casing and … [illegible] 6" liner. Bridged well at 1986′ with Spruce Tree and filled with sand pumpings. Put in wooden plug 5′ long and drove down tight. Put 4 bags cement on top plug. 8 1/2" [?] casing could not be pulled. Cut 548′ [?] off bottom of casing and pulled rest. Put in bridge at 408′ and filled up with sand pumpings. Filled up hole to 225′, then put in wooden plug with three bags cement on top. Pulled 12 1/2" and 15" casing and filled hole to top."*

Sometimes, lead plugs were used to seal the abandoned wellbore, perhaps the most effective seal used in the early twentieth century.

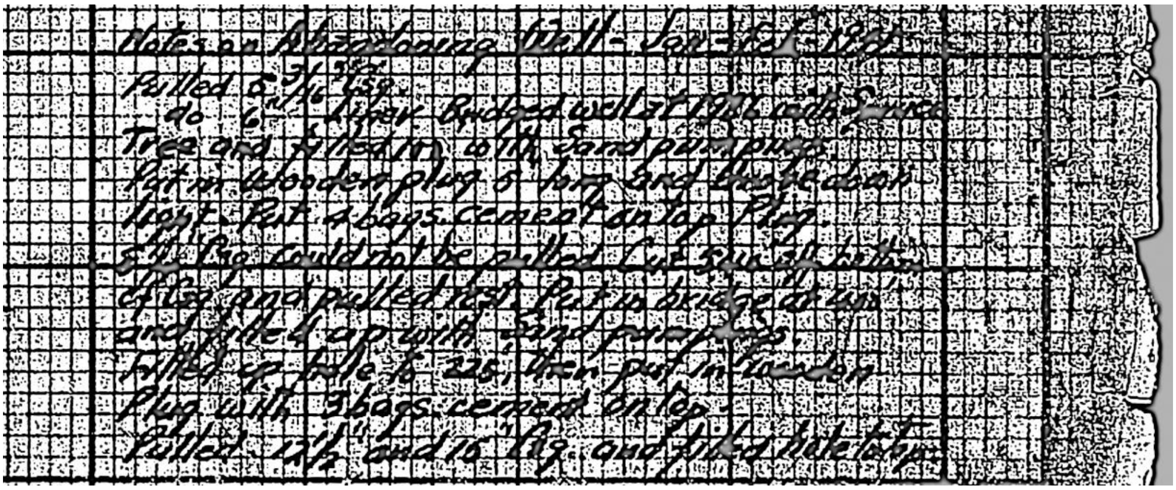


Figure 12 - Notes from an abandoned well. The text is typed in the preceding paragraph.

Lebel and others (2020) have reported that there are ~124,000 plugged and abandoned wells in California, USA compared with only ~63,000 active wells. *Idle wells*, of which there are ~38,000 in California, were sampled and, on average, were found to exceed the methane emissions from plugged and abandoned wells. In California, the state's Geologic Energy Management Division can force previous owners to pay for plugging and abandonment. Technically, this means that there should be a smaller orphaned well problem. Additional funding will require regulatory improvements, which can include regulations or policies that will reduce the number of wells being orphaned in the future.

The suspension of production (sometimes referred to as *suspended wells* status) often indicates reservoir depletion, although jurisdictions may not require abandonment and plugging of these suspended wells because its cost is likely to be significant for small oil and gas businesses. These wells may eventually become the responsibility of the state or province; thereby, the cost of plugging and abandonment is transferred to the taxpayer.

Kang and others (2021) point out that roughly 60% of all oil and gas wells that have been drilled in the USA are currently inactive—some 2,700,000 wells—but only one third of the total are plugged and abandoned. The Interstate Oil and Gas Compact Commission (IOGCC) (2021) estimates average cost on the order of US$25,000 to plug and abandon a single orphan well. Raimi and others (2021) estimated a cost of US$20,000 for plugging abandoned oil and gas wells but noted the cost could be as high as US$1,000,000 in some situations. In its April 2024 Onshore Oil and Gas Leasing Rule, the US Bureau of Land Management estimated that the average cost of plugging 22 wells in three USA states was US$71,000 per well. Experience in Ontario, Canada has shown plugging costs can be in excess of CDN$200,000 per well (US$150,000/well) where abandoned wells are emitting sour gas (CH_4 + H_2S) under artesian pressure (Jackson et al., 2020).

2.3.2 Locating Abandoned Oil & Gas Wells

Petroleum producing jurisdictions—e.g. states, provinces, or nations—generally maintain registers of the location, history, and condition of oil and gas wells after they are drilled and after abandonment. However, such registers were not developed as reliable reference libraries until the twentieth century, long after the modern oil industry had begun in the 1860s. Therefore, many earlier oil wells are missing from these registers. The earlier wells would have been drilled by cable-tool rigs with the casings withdrawn following abandonment to be re-used by the driller. The advent of effective rotary drilling with drilling fluid circulation in the last decade of the 1800s allowed more rapid and deeper drilling, but cable-tool drilling persists today in shallow plays in strong rocks.

During the two world wars of the twentieth century, many older casings were pulled from wells because of the extreme shortages of steel. This absence of steel has made the detection of such abandoned oil and gas wells problematic. Cementing of steel casing developed with the advent of deeper wells and the need to control subsurface pressure and the cement prevents removal of the casing from the well. Rigorous standards and enforcement for well design, pressure control, cementation, surface water protection, and good quality abandonment only developed in the post-World War II era. These standards continue to evolve, particularly to address environmental issues, and regulatory agencies continue to adjust their well-completion requirements to reduce the incidence of leaky wells and other legacy problems.

An abandoned and improperly plugged oil or gas well is a short circuit that may allow fluids to escape to the ground surface or contaminants to enter shallow aquifers, or allows groundwaters to invade deep petroleum reservoirs. For example, Lyverse and Unthank (1988) describe the contamination of a shallow municipal aquifer along the Ohio River, USA by chloride from nearby abandoned oil wells. Williams and others (2021) have documented gas releases to the atmosphere, specifically methane emissions, from abandoned oil and gas wells across North America. They estimated that there are at least 4,000,000 abandoned wells in the USA, at least 370,000 such wells in Canada, and that methane emissions from these abandoned wells are underestimated by roughly 150% in Canada and 20% in the USA.

However, Perra and others (2022) found that it is difficult to determine the extent of contamination in the transition zone, which is the interval between deep oil and gas producing formations and shallow potable groundwater that might potentially be affected by cross-contamination due to abandoned boreholes. For three hydrocarbon-producing areas in the Western Canada Sedimentary Basin, they established that the potential for cross-formation contamination because of a lack of cement completions is significant and fluid flow patterns may have been altered by this lack of zonal isolation arising from poor cement completions in older oil and gas wells or exploration boreholes.

The location of abandoned oil and gas wells is usually accomplished by searching for the ferromagnetic response of the iron or steel casings used to complete the well. Aeromagnetic surveys can thereby identify unknown wells provided the ferromagnetic response is sufficiently strong. The US National Energy Technology Laboratory (NETL) in Pittsburgh has conducted several field studies both in residential and commercial areas (Hammack & Veloski, 2016) and in largely rural areas (Hammack et al., 2016). More recently, NETL and others describe the successful location of abandoned oil and gas wells without steel casings in Pennsylvania and Wyoming, USA, (Saint-Vincent et al., 2020; Saint-Vincent et al., 2021), New York, USA, (Nikulin & de Smet, 2019) and New Brunswick, Canada, (Butler et al., 2019) using helicopter and drone aeromagnetic surveys as well as LiDAR.

2.3.3 Current Practice

A properly abandoned well is sealed in-situ such that the oil and gas producing zone is completely isolated from shallow groundwater zones and the ground surface. The oil and gas operator must design an abandonment program that identifies wellbore integrity issues, oil and gas zones, groundwater zones, and the cement's integrity. The general principles followed today are summarized by the State of Texas (USA) Administrative Code (no date) (Rule 3.14):

1. Wells shall be plugged to ensure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected.
2. Cement plugs shall be set to isolate each productive horizon and usable quality water strata.
3. Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe.
4. All cement for plugging shall be an approved American Petroleum Institute oil well cement.

In cased wells, the cement plugs are placed inside the casing. The cemented annulus outside the casing is considered an adequate long-term seal for abandonment. In exploration boreholes, which are drilled and then abandoned shortly thereafter—they are not developed for production hence there is no installation of a production casing—the methods of plugging differ. A cement plug must continuously fill the entire hole as no casing is present.

In past decades, and currently in some jurisdictions, during well construction it was permitted to cement the annulus surrounding the production casing only partially. When the well was later abandoned, this allowed the withdrawal of the uncemented casing, followed by the placement of plugs in the open hole against the rock mass. Issues have arisen because of this practice due to autogenous shrinkage of the cement or inadequate zonal isolation of shallow gas-rich formations.

The basic steps of the modern abandonment process are described in the following sections. The reader who wishes more information is referred to industry documents such as NPC (2011), Van Dyke (1997), Nelson (1990, 2012) and Saponja (1999). Vrålstad and others (2019) present an excellent modern summary of well abandonment.

Preparing the Wellbore

The first step of the abandonment process is to remove tools and hardware from the wellbore such as production tubing and packers, uncemented casing, pumps, and bridge plugs or other obstructions. If downhole equipment cannot be removed, then the wellbore abandonment strategy may need to be changed, in which case the new abandonment strategy may require special permission from the regulator.

Following removal of downhole equipment, the borehole must be cleaned, typically by lowering a tubing and flushing the wellbore with a circulating fluid capable of controlling borehole pressures if they exceed the hydrostatic water column. This fluid may contain additives to achieve the proper fluid properties. Circulation is produced by injecting the fluid down the tubing and extracting it at the surface. If sealing an uncased borehole, it is important to remove the mud and mud cake from the zones of the wellbore where cement will be emplaced as mud often retards setting of cement and may cause poor bonding to the walls. Mud-contaminated cement must be displaced from the desired zone with a dispersant fluid to ensure proper cement bond development to isolate the zone. In a cased borehole, hydrocarbons should be removed to ensure the casing is water wet, i.e., is not hydrophobic. This will allow the best possible cement bond.

Plugging

Cement plugs are emplaced in open boreholes or within cemented production casing under a variety of well conditions using different methods. Cement plugs can be placed in single or multiple stages in the borehole depending on the needs of the scenario and the regulatory stipulations. The most common method used for the placement of cement plugs in uncased holes is the *balanced plug* method, whereby a calculated and measured volume of cement is introduced at a specific depth in a well such that the static pressure exerted by the cement balances the column of fluid in the well annulus. In Alberta and other Canadian jurisdictions, an abandoned cased well is usually plugged by *dump bailing* an 8 m column of cement onto a steel and elastomer bridge plug installed in the casing prior to adding cement (Watson & Bachu, 2009; AER, 2023). This type of plug has an expandable elastomer seal that isolates the reservoir below the plug. Cement plugs do not prevent gas migration up the annulus behind the casing, i.e., between the casing and the borehole wall.

An important consideration in the use of cement plugs is their compressive strength development—the time-dependent ability of the cement plugs to sustain a fluid pressure or load without failure. For the purposes of inhibiting wellbore leakage, the plug must have enough strength to inhibit gas migrating through the cement during the gelation or cement-setting phase (Crook & Heatherman, 1998). When the cement slurry has developed a static gel strength (SGS) of 500 lbf/100 ft^2 (239 Pa), it has enough solidity to prevent formation fluid migration. To minimize the risk of gas migration, a good cement slurry should develop a critical SGS in a period of less than or equal to 45 minutes (API standard 65-2; API, 2010↗).

Compressive strength testing shows that cement gel strength development times can be from three to five times longer with as little as 10% mud contamination, compared to development times for mud-free cement. Most balanced cement plugs fail because of fluid flow in the borehole including cross flow of formation fluids or a density or viscosity mismatch between a balanced plug and wellbore fluids. These effects are exacerbated if there are several widely-spaced open perforated zones with unbalanced pressures within the well.

In cases where there is no cement in the annulus behind a casing or the cement has been identified as inadequate, it may be necessary to remediate the cement in the annulus to isolate permeable zones. The *cement squeeze* method is used to accomplish this. The *perf-and-squeeze* method involves perforating the casing or liner with bullet or shaped-charge *perforating guns*, isolating the new perforations with a double packer (one packer above and one packer below the perforated section), and pumping (*squeezing*) cement under pressure through the perforations into the external annulus, where the fluid cement will presumably fill permeable pathways, clogging the pathway or sealing the source formation, and form an impermeable barrier. Perforating the casing is a means to access permeable zones or gas source zones behind the casing, as well as inadequately cemented zones. Abrasive methods—high pressure sand-water slurry—and other alternative methods have also been used—e.g., laser, mechanical. A section of the casing can also be milled out to install a longer plug with direct contact against the rock wall. In addition to cement plugs, mechanical plugs such as bridge plugs and cement retainers play a role in stopping fluid flow in a wellbore (NPC, 2011). The success of this remedial measure may be checked with cement bond logging of the leaky section before and after the squeezing.

Gases emitted from the surface casing vent, called the *bradenhead* valve in the USA (Figure 2), are referred to as surface casing vent flow and may require sealing at an appropriate depth. The governing regulatory body will require the depth and formation of the gas source to be identified and the source to be sealed to eliminate gas flow from the reservoir or from shallow non-commercial zones above it. The source depth might be determined by noise logs (Molenaar et al., 2010) or isotopic fingerprinting of gases (McIntosh et al., 2018), but the specific entry point into the outside annulus is often difficult to determine because of the endemic presence of natural gas in the *intermediate zone* below the surface casing. If the surface casing is shut in, then pressure can build up and *gas migration* may occur outside the surface casing and cause migrating *fugitive* or *stray gas* to enter shallow aquifers or rise to ground surface. Gas migration is defined as a flow of gas that is detectable at ground surface outside of the outermost casing (Forde et al., 2019c). Perf-and-squeeze operations are used to enter and seal the annulus behind the casing to eliminate surface casing vent flows and gas migration occurrences, which are often the result of poor primary cementing operations (Figure 4).

Diller (2011) described the sealing of a poorly abandoned well, which was required prior to the injection of acid gas $(CO_2 + H_2S)$ from nearby thermal-bitumen recovery wells into a depleted sandstone reservoir. Without re-entering and sealing this well, the acid-gas storage plan would be compromised. At a cost of CDN$5–6 million, Shell Canada spent 60 days following and adjusting a well-abandonment plan that resulted in the successful sealing of the abandoned well providing *zonal isolation* of the injection formation with respect to an overlying gas reservoir and groundwater. This case history is instructive in showing how iterative planning is important in overcoming problems encountered in the mitigation of risk from poorly abandoned oil and gas wells. In also highlights the high costs that may accompany sealing attempts.

A workshop held by the USA National Academies of Sciences, Engineering, and Medicine (2024) summarized case histories of plugging and abandoning wells across the USA. It emphasized that experience with plugging and abandoning off-shore wells in the Gulf of Mexico had resulted in many poor-quality abandonments that on re-inspection indicated sustained casing pressure from poor practice. This experience was summarized as follows (National Academies of Sciences, Engineering, and Medicine, 2024, p.24):

- cementing all gas-emitting zones is essential for successful abandonment including non-productive formations;
- mechanical plugs alone are insufficient and long-term hydraulic seals are necessary;
- pipes that are to be cemented in place should first be cleaned with a surfactant to ensure cement bonding;
- the benefits of cement additives (e.g., accelerators to reduce setting time or retarders to delay it) and cement testing should be recognized;

- allowing sufficient time for a cement seal to set and reach its compressive strength is essential, especially if the temperature downhole is cool;
- the top of the cement column should be verified after every plug is set;
- it should never be assumed that steel will maintain its pressure integrity over time;
- elastomers used as part of a seal will fail eventually;
- following the addition of each cement plug, the absence of gas bubbles above the plug should be confirmed;
- should a plug be deemed to have failed through this bubble test, then it should be replaced; and,
- the presence of gas bubbles in the annulus requires treatment at the depth of the leakage into the annulus.

Therefore, redundancy should be built into the plugging and abandonment of legacy hydrocarbon wells such that no single failure will cause significant gas emissions from the abandoned well.

The literature on gas migration and mitigation is strongly prejudiced to success stories, technology claims, and incomplete understanding of the physical processes. Independent reviews of these successful claims are usually absent and there has been no systematic data analysis to adequately capture gas migration and mitigation success and failures. Current understanding is based on anecdotal evidence. This speaks to the complexity of the issues, as well as to the unavoidable human tendency to avoid speaking of errors or shortcomings. This issue is further discussed in Section 4: Forensic Analysis.

Cement Plug Evaluation

Testing is required to ensure that the plug is placed at the proper level and provides adequate isolation of permeable zones. The plug depth can be verified by *tagging* its top. Tagging the top of cement is a straightforward method using drill pipe, tubing, or wireline methods to verify the cement top depth. This method allows the depth of the cement plug to be determined, but it does not verify that the cement has set properly or created a sufficient seal to resist differential pressures.

Integrity tests can be carried out by pressure testing or swab testing. Applying pressure to the top of the cement to test the seal identifies the completeness of the plug, but it may damage the plug or cause damage elsewhere in the casing. *Swabbing* the wellbore employing *swab cups* lowered by wireline to remove fluids causes a loss of pressure in the wellbore at the plug, increasing the differential pressure across the plug. The fluid level recovery in the wellbore above the plug can be monitored to determine the effectiveness of the plug. This is a time-consuming method, and both pressure application tests and fluid level recovery tests may not be diagnostic if fluid can enter or leave the wellbore from other locations, falsely indicating that the plug has failed. Conversely, both methods may indicate that the cement plug is functioning well when the seal and mechanical strength is actually provided by the *bridge plug* on which the cement plug was placed. The bridge plug depends on an elastomer seal and is not considered permanent; its performance is expected to deteriorate over time.

In addition, a direct in-situ test was developed by Gasda and others (2008) to measure the effective permeability of the annular cement seal. This Vertical Interference Test requires the perforation of two sections of casing between which the annular cement seal is tested by pressurization. The lower packed-off section inside the well is pressurized such that the pressure is communicated to the upper packed-off section via the annulus. Unfortunately, the test is costly in that it requires specialized equipment and analysis, perhaps the injection of large volumes of brine and the further expense of a workover rig.

Identifying Wellbore Leakage

Abandoned oil and gas wells may develop leaks relatively soon after abandonment or progressively over time; the pathway development mechanisms are generally different for the two extremes. Early leakage tends to be a mechanical or placement failure, such as placement of a cement slurry that is not dense enough and experiences autogenous shrinkage. Long-term leakage issues tend to be more related to build-up of a free gas column (via a pressure differential and buoyancy), chemical deterioration of cement or steel casing (e.g., corrosion in shallow acidic zones), or slow development and interaction of pathways within the naturally fractured rock mass that likely also contains free or dissolved gas (i.e., development of partial pathways away from the wellbore proper).

Gas migration is more likely if faults or highly permeable channels are intersected by the wellbore, as shown in Figure 13. Major pathways for the movement of gases and groundwater between strata should ideally be identified to conceptualize preferential flow pathways. Preferential pathways may also be linked to the failure of poorly plugged exploration boreholes, or poorly cemented production wells. Gas migration is discussed further in Section 4. Exercise 1↴ and Exercise 2↴ address brine pressure and gas flow in the well and subsurface shown in Figure 13.

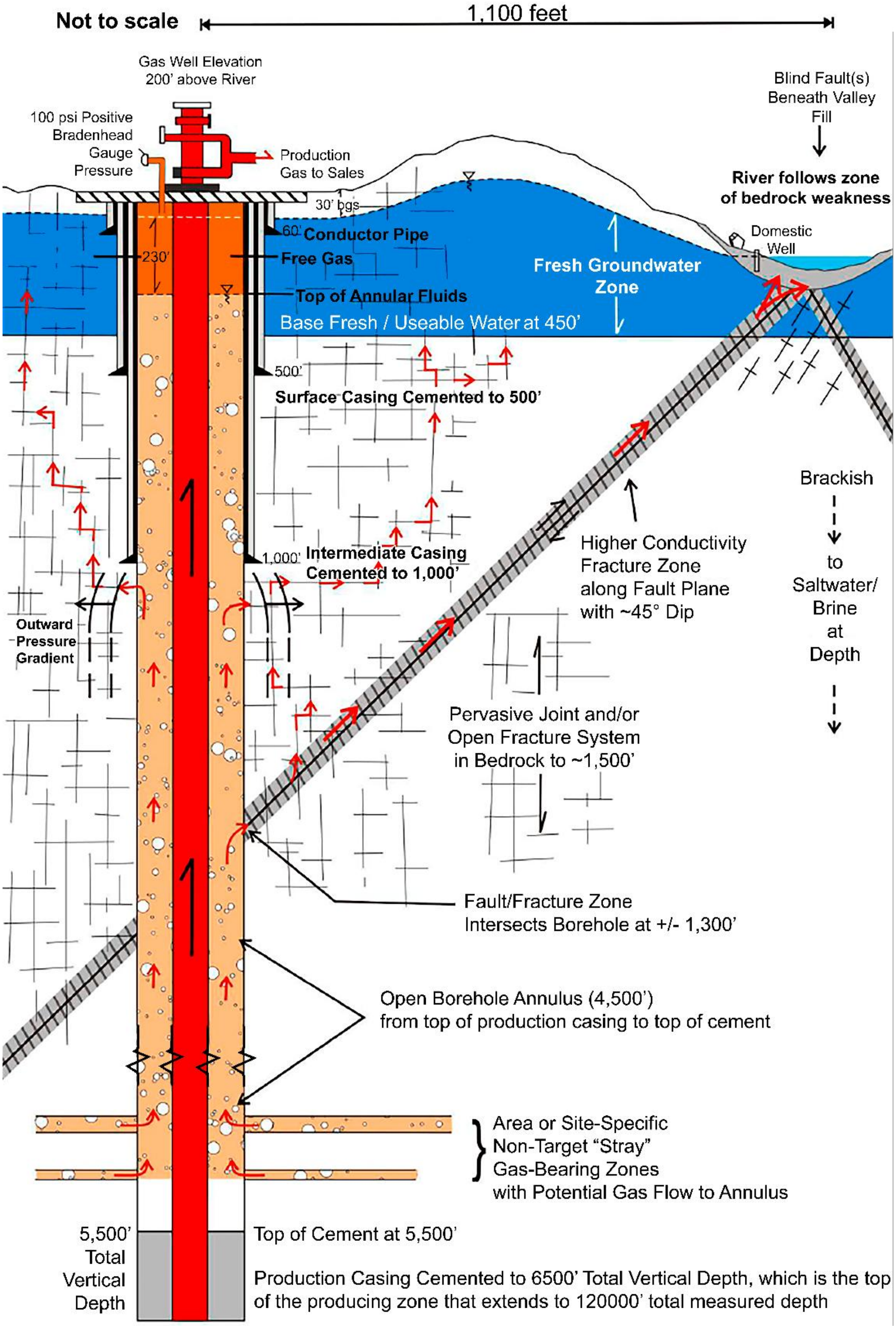


Figure 13 - Example of conditions under which gas migration is more likely. Marcellus shale gas well in northeast Pennsylvania, USA. Borehole configuration is depicted from land surface to the top of the producing zone, which is not shown and extends from 6,500 ft depth to 12,000 ft. Shut-in casing head valves promote gas pressure build up and gas migration into bedrock. Cement is absent from the annulus over a distance of 4500 ft, ~1500 m. Red arrows represent gas migration pathways. (simplified from personal communication with Pete Penoyer, 2013, US National Park Service, Fort Collins, Colorado, USA). 1 foot (') ~ 0.3 m.

Prior to conducting the surface abandonment (capping, clean-up), testing can be conducted to determine if gas, liquid, or any combination of substances is escaping from the wellbore (Watson & Bachu, 2009). Such testing will likely involve inspection of vegetation in the area surrounding the wellhead for signs of distress, measurement of gas flow from the surface casing vent, or sustained casing pressure recorded at the casing head (shown as a *bradenhead* in Figure 13), and measurement of *gas migration*—flow of gas that is detectable at land surface outside of the outermost casing. A serious gas migration issue may constitute a fire or public safety hazard, or an environmental risk of groundwater contamination in nearby water supply wells or monitoring wells outside the lease area of the oil or gas well. However, monitoring to identify wellbore leakage after abandonment is not routine (a practice that is widely accepted), except in Alberta, Canada which requires surface-casing vent flow and soil gas testing after well abandonment and before surface restoration, and a few other Canadian provinces that follow this protocol. Many jurisdictions in the USA and elsewhere lack a clear regulatory framework for post-abandonment monitoring.

Repair Requirements

Repair or remediation of wellbore leakage depends on the regulatory system in place. In Alberta, Canada, the well must be tested for surface-casing vent flow within 90 days of drilling rig release (i.e., well completion). Testing for gas migration must also be carried out within 90 days for specified areas in Alberta that have experienced high rates of vent flow in the past. The licensee of a well with a serious surface-casing vent flow or gas migration problem must repair the problem within 90 days of the discovery of the problem, most likely by a downhole cement squeezing operation. Here, we define a serious rate of gas emission as being greater than the Alberta standard of 300 m^3/day or ~200 kg/day (i.e., ~281 m^3 of CH_4 at standard temperature (0 °C) and pressure (1 atmosphere)) during the operational life of the well. Non-serious gas emissions must be addressed at the time of well abandonment. Alberta's regulations are among the most prescriptive to be found in North America and are generally copied by other Canadian provinces because of the substantial empirical basis from which they have been determined.

Colorado, USA stipulated in 2021 that the annular gas pressure on the bradenhead, expressed in psi (1 psi ~ 7 kPa), must not exceed 30% of the true vertical depth of the surface casing shoe. This would yield a maximum allowable bradenhead pressure of 300 psi for a surface casing shoe at 1,000 ft (2000 kPa at 305 m); greater pressures would require a sustained casing pressure management plan. Mitigation of this pressure might involve venting the gas (*bleed off strategy*), diverting the gas to flaring, or downhole cementing of the leaking gas zone. Colorado's regulation is relatively strict compared with other USA states where rules vary significantly or do not exist.

El Hachem & Kang (2023) reviewed a variety of repair strategies. They stress the need for implementation of strict well suspension and plugging deadlines to reduce methane emissions from unplugged abandoned wells.

Cut and Cap

The final field-step of the abandonment process is to cut, cap, and cover the well. Typically, the casing string must be cut off a minimum of 1 m below the final grade of the site. Before the well is cut and capped the presence of wellbore leakage must be assessed, as described above. Depending on the jurisdiction, the cap may be placed as a fully welded seal, or with a small hole left open to prevent pressure build-up once it has been verified that no wellbore leakage occurs. In some regions, such as Pennsylvania, USA, a surface marker is required so that the location of the well can be identified. However, in many other places, the land is reclaimed such that there is no evidence of the well at the ground surface, which may become overgrown with vegetation.

3 Potential Environmental Pathways

In this section we summarize the primary pathways (i.e., failure modes) which could result in a spill or release in the context of upstream oil and gas production. As these are increasingly common and often controversial, we pay particular attention to hydraulic fracking and its potential impacts.

3.1 Groundwater Contamination

3.1.1 Well Pad Activities

Well pad operations are shown in Figure 14. Similar activities in other industries that handle and transmit fuels and chemicals, e.g., fuel tank farms, gasoline service stations, and manufacturing industries using solvents, have resulted in fluid leakage and shallow groundwater contamination. The following well pad activities are important in the context of potential groundwater contamination.

- Oil and gas production requires water and wastewater storage and management. Such facilities (water impoundments, flowback tanks, lagoons, flow lines) are subject to leakage. The probability of leakage is relatively low, but should it occur with water-based fluids that have hazardous chemicals or high dissolved salt contents, groundwater contamination may occur. For example, extensive brine contamination plumes were detected by electromagnetic apparent conductivity in shallow aquifers on the Fort Peck Indian Reservation, Montana, USA (Engle et al., 2014; Thamke & Smith, 2014).
- It is necessary to store significant quantities of fuel on each well pad for drilling and production purposes thus storage tanks of several thousand liters of fuel are present on each multi-well site during the active development phase.
- At each well pad, surface activities require clearing of vegetation and excavation for production and handling activities. This can cause erosion and sediment runoff, particularly where surficial sedimentary materials such as glacial till or outwash sand are present and exposed. Until the site is re-vegetated, the sediment runoff will create small alluvial debris lobes in topographically low areas as shown by Williams and others (2008).
- Truck transportation of fuel to well pads is necessary and may represent the highest hazard for spillage of fuel. The consequences of such spills are well understood by regulatory agencies, and remediation of the spills is proficiently practiced but difficult and often incomplete.
- The produced water from hydrocarbon reservoirs often includes fracking flowback fluids and are likely saline. They contain high concentrations of chloride and brine-related ions (e.g., Br, Na, K) that require careful handling and disposal. The total dissolved solids (TDS) content of this produced water may

be in the range of 30,000 to 300,000 mg/L, which is typical for brines from the Marcellus Shale (Capo, 2014; Engle et al., 2016). The produced water may also contain metals such as barium and radium (Rowan et al., 2011) in concentrations exceeding aquatic toxicity guidelines and drinking water limits. Poor handling of produced water and inadequate disposal practices were implicated in the deterioration of stream-water quality in several streams in Pennsylvania, USA within the Marcellus play (Brantley et al., 2014; Olmstead et al., 2013; Wilson & VanBriesen, 2012).

- Drill cuttings are chips and pulverized rock particles produced by the drilling operation in the form of a slurry-like waste that may contain oily material and residual drilling fluid (Leonard & Stegemann, 2010). Cuttings are typically disposed in a special landfill, but if oil-based drilling muds are used, special drill-cuttings treatment is required and recycling or proper disposal of oil-based drilling fluid must be implemented.
- Flowback solids include proppants and other materials recovered during hydrocarbon extraction that are captured during filtration of the produced water. These materials, such as filter cake from treating hydrocarbon wastewater, may be radioactive with potentially hazardous concentrations of radium (Lauer et al., 2016), thorium, uranium or even high amounts of potassium (including the radioactive isotope ^{40}K) referred to as NORM (Naturally Occurring Radioactive Materials).
- Other sources of solid waste may include pipe scale (often classified as NORM), soil contaminated by spills or leaks of hydrocarbons or other materials, tank bottom sludge, and calcium-rich sludges from water treatment plants.

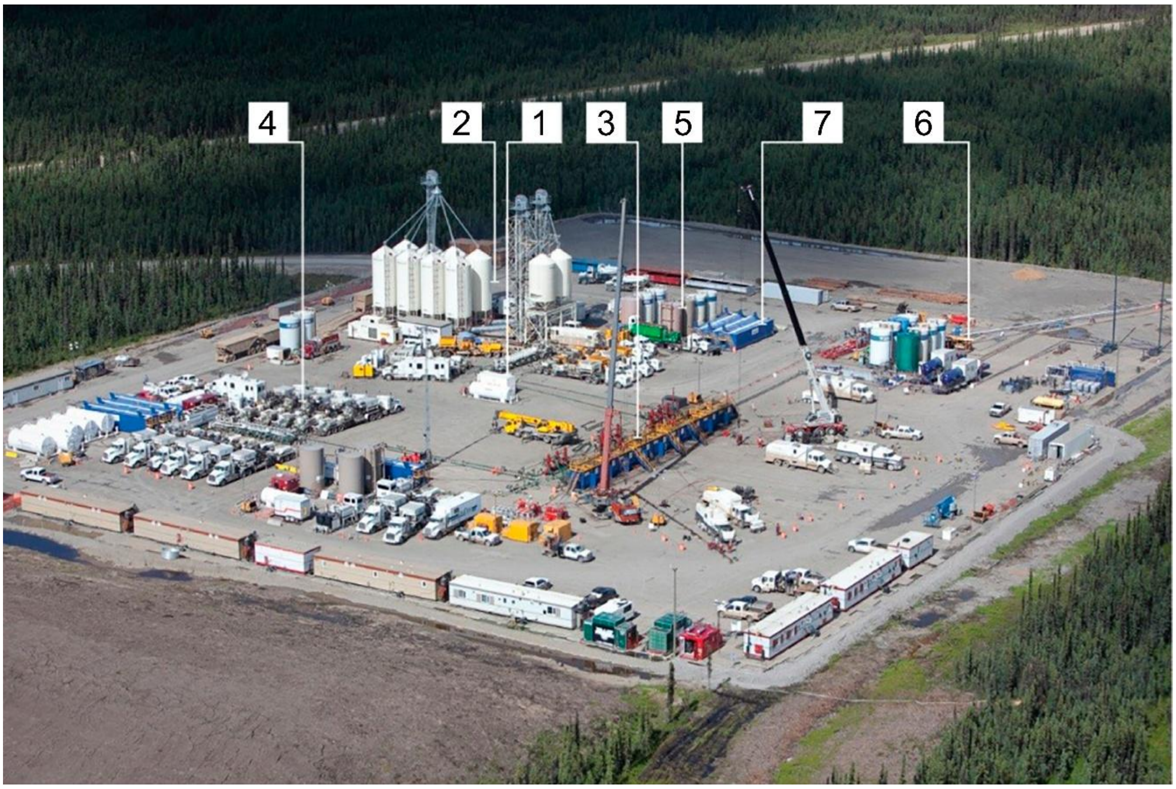


Figure 14 - Surface infrastructure of a well-pad site during hydraulic fracturing stimulation ("fracking"). Source: Council of Canadian Academies, 2014 (photograph courtesy of Nexen Energy, ULC). The numbered labels are as follows.

1. Data/Satellite Van: To monitor and control treatment operations. Closed circuit TV coverage of entire location. Satellite transmission of job data for real-time monitoring from remote locations.
2. Sand Conveyor: To store proppant (sand) and to feed it to the blender mixing tub.
3. Well head.
4. Blenders: Equipment to blend fracturing fluid, chemical additives, and proppant and feed it to the pumping units.
5. Pumping units: High pressure pumps to pump the fluid into the well.
6. Chemical vans: Storage, transportation, and metering units to feed additives into the fracturing fluid stream as it is being pumped down the well.
7. Test equipment: To receive and measure flowback fluid in a controlled manner and to separate fluids with gas being sent to the flare stack to be burned.

3.1.2 Contamination By Hydraulic Fracturing Fluids

Hydraulic fracturing has been criticized by environmentalists as a technology that is environmentally dangerous to shallow groundwater. However, given that there are no reliable published accounts in refereed journals describing such contamination, this claim remains in the realm of conjecture. Myers (2012) attempted to discredit deep hydraulic fracturing through unconstrained modeling results, but his article was strongly criticized (Cohen et al., 2013) for its inappropriate numerical modeling. Poorly conceived model conditions and extreme assumptions guaranteed that the model would produce negative effects. Although hydraulic fracturing fluid contamination along legacy wellbores in the vicinity of a fracking operation has been observed (Section 4), there have been no known incidents of contamination due to uncontrolled upward migration of induced fractures and, thereby, of hydraulic-fracturing fluids.

Practice in North America has shown that the environmental impacts related to hydraulic fracturing operations are reasonably well understood. The critical review of hydraulic fracturing by Dusseault and Jackson (2014) indicated that several factors prevent or, at least, inhibit uncontrolled upward propagation of induced fractures. They include the following.

- **The construction of the production well** (API, 2009): Hydraulic fracture stimulation is done through the production tubing that is sealed from the production casing (as shown in Figure 2), not through the production casing itself, and the annular pressure within the production casing is monitored. If there is a breach in the production tubing, it is detected immediately. The bottom part of the production casing is almost always well-cemented because the deeper cement sets under a higher hydrostatic head, densifying the cement paste through pressure filtration where fluid moves into the surrounding strata while solids remain in the cement (i.e., reducing the water to solids ratio) before it sets, producing a superior seal.
- **Propagation of induced fractures:** Hydraulic fracturing in zones where the minimum principal stress is horizontal preferentially induces formation of vertical fractures above, rather than symmetric fractures around the injection point (Figure 9 and Figure 15). This occurs because the rock mass fracture gradient (the minimum stress gradient) is on the order of 18 to 23 kPa/m, but the pressure gradient in the fracturing fluid is about 10 to 13 kPa/m. As shown in Figure 15, this leads to a greater driving pressure at the top of the fracture than at the bottom, leading to fractures forming above the injection. The upward vertical fracture formation is counteracted by *leak-off* (lateral migration) of the fracking fluid into naturally porous or fractured strata (Warpinski & Teufel, 1987; Wang et al., 2018) and, especially, the imbibition of the fracking fluid within the shale matrix (Engelder et al., 2014) which limits their upward migration.
- **Imbibition of injected fluids and associated strain:** Some of the volume of the injected fluid flows back as brine at the end of each hydraulic fracture stage; the rest is accommodated within open or partially open fractures in the shale gas reservoir or is absorbed by the shale itself (Engelder et al., 2014; Edwards et al., 2017; Osselin et al., 2018). Therefore, irrespective of any favorable gradient, the availability of brine for migration from the target formation to shallower horizons—as suggested by Warner and others (2012)—is limited because the brine is trapped by capillary forces, low permeability, and a fluid density that is greater than the fluid density in overlying strata.
- **Effect of uplift and surface erosion on fracture orientation:** All shale gas basins identified to date are in uplifted, eroded sedimentary basins, including those

associated with glaciation in Canada and in North and South Dakota, USA. In these eroded sedimentary basins that were uplifted by isostatic rebound following glaciation, the stresses in the earth are redistributed in such a way as to create a zone ranging from 100 m (300 ft) to as much as 1000 m (3,000 ft) below the ground surface, where fractures will not tend to propagate vertically upward, but instead turn and propagate horizontally, parallel to bedding (Han et al., 2009) as shown in Figure 9. This is because the vertical stress is the smallest of the principal stresses at shallower depths.

- **The nature of the overlying strata:** Shale gas reservoirs are generally overlain by low-permeability strata, mostly low-porosity carbonates and shales. They are usually somewhat naturally fractured, as has been observed above the Marcellus and the Utica Shale in Pennsylvania, USA, but it is expected that over time natural fractures at depth are largely closed by high compressive stresses. Furthermore, there are often horizontally extensive permeable zones, usually sandstones, in the sedimentary sequence above the reservoir being stimulated. If a vertically propagating facture intersects such zones, massive leak-off takes place, inhibiting further vertical propagation.
- **Design of hydraulic fracture stimulation:** The companies that undertake hydraulic fracturing use mathematical models and monitoring data to design their injection operation in such a way that the fractured zone, including the region within which there is a beneficial perturbation of the natural fractures (the stimulated rock volume), does not extend significantly beyond the top of the shale-gas target zone. The predictive ability of these models improves with time because data are collected to calibrate the models. Furthermore, there is no economic incentive to induce fracturing above the target horizon because it would not add to the productive capacity of the well, so, fracture fluid volumes are limited to avoid such waste.
- **Effects of production from shale-gas reservoirs:** It is expected that 15% to 35% of the total gas in place will be produced from the shale gas zone over a 10 to 25-year well life (King, 2010). This production leads to pressure depletion, which means that the target becomes a pressure sink that fluid flows towards, rather than away from.

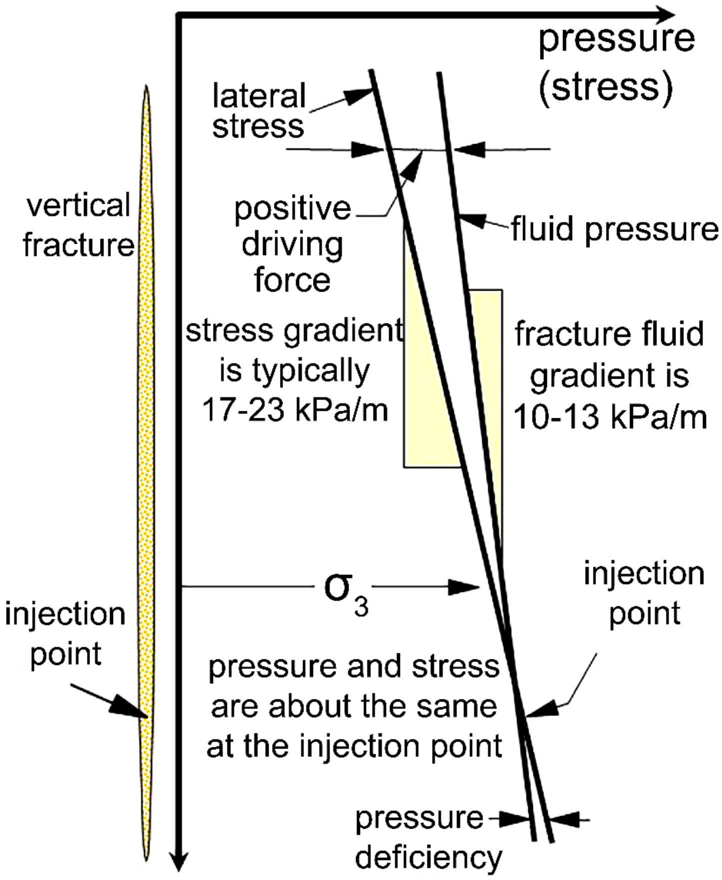


Figure 15 - Hydraulic fractures propagate upward because of differential pressure gradients. The minimum principal stress in the formation is labeled σ_3. The lateral stress and the fluid pressure are about equal at the point where fracking fluids are injected. However, the stress and the pressure have different gradients, such that the fluid pressure is greater than the lateral stress at depths shallower than the injection point. This positive difference between pressure and stress drives the opening of fractures (adapted from Dusseault & Jackson, 2014).

For these reasons, it is unlikely that vertical fractures induced by hydraulic fracturing will migrate more than a few hundred meters. A review of natural and stimulated fractures by Davies and others (2012) concluded that the probability of a stimulated fracture exceeding 350 m is 1 percent. To double the size of the fracture the fluid volume must be increased by a factor of 8 (Dusseault & Jackson, 2014, pp. 115–116). Indeed, Fisher and Warpinski (2012) found that the vertical extent is usually measured in tens to hundreds of feet, not hundreds of meters. The database of vertical fracture distances compiled by Fisher and Warpinski (2012) was used by Kim and Moridis (2015, p. 128) to conclude that "their maximum vertical lengths from the center of perforation are approximately no greater than 460 m".

Because the injected fracking fluid is largely absorbed by the shale that is the target for the fracturing operation, Engelder and others (2014) pointed out that much less than half of the injected fluid returns to the surface with the recovered gas, while the remainder imbibes (i.e., is absorbed) into the shale's pores or may even leak off into horizontal bedding plane fractures. This conclusion has been confirmed for shale in Alberta, Canada (Osselin et al., 2018), for fracking in British Columbia, Canada (Edwards et al., 2017) and under general conditions prevailing in fractured shales (O'Malley et al., 2016.). Consequently, relatively little injected fracking fluid remains available for continued vertical fracture propagation to shallow aquifers.

However, some industrial accidents occur and two accidents associated with hydraulic fracturing have been documented in Canada by the Alberta Energy Regulator (formerly Energy Resources Conservation Board, ERCB). These include the following.

- *Inter-WellBore communication*: A study near Innisfail, Alberta (ERCB, 2012a) determined that a horizontal well had been drilled to within 129 m of an offset well—i.e., a producing well close to the horizontal extension of the fracked well—that subsequently discharged ~500 barrels (80 m^3) of hydraulic fracturing and formation fluids at the surface when the new well was fractured (Figure 16).
- *Premature fracking*: An accidental hydraulic fracturing incident occurred in northern Alberta that caused fracking fluids to penetrate a shallow aquifer. The rig crew believed that they were fracturing at the target depth (1.5 km below ground surface). However, they accidentally perforated the casing at 136 m and injected fracking fluids into a shallow sandstone aquifer (ERCB, 2012b). No water supply wells were contaminated because of the remoteness of the well in northern Alberta.

Figure 16 - Inter-wellbore communication event, Innisfail, Alberta, Canada, January 2012 (photo from Calgary Herald, January 17, 2012). Hydraulic fracturing fluids injected at one well were discharged under high pressure from another well to land surface.

Most cases of inter-wellbore communication involve pore-pressure pulses—i.e., transmission of hydraulic fracturing fluid-pressure increases to the offset well in the form of a pressure increase (sometimes called a *pressure kick*) at the affected well—a different mechanism than caused the breakthrough of fracking fluids at Innisfail, Alberta, Canada. Experiences of pore-pressure pulses in the Barnett Shale of Texas, USA indicate that a distance of ~200 m is sufficient to allow such inter-wellbore communication (M. D. Zoback, Stanford University, personal communication, November 30, 2012). Kim (2012) indicates that in Alberta, Canada, the measured distances over which pressure pulses can cause inter-wellbore communication are larger, with a median value of ~250 m and a maximum distance of 2400 m. In British Columbia, Canada, evidence of pressure pulses over a distance of 4100 m have been noted (K. Parsonage, BC O&GC, personal communication, January 24, 2014). In general, these pressure pulses are small compared to the static pressures involved.

Because the compressibility of water is low, a pore-pressure impulse can easily be transmitted great distances, but physical flow of hydraulic fracturing fluids is limited to the region proximal to the fracking treatment. In addition, flow over longer distances involves dispersion, dilution, and rock-matrix absorption of agents within the water, attenuating the potential environmental impact. Nonetheless, Alberta, Canada, published regulatory guidelines to reduce the probability and impact of this type of pore-pressure transmission (AER, 2013).

Dusseault and Jackson (2014) concluded that deep hydraulic fracture stimulation was not a significant environmental risk, except when abandoned or *suspended* (i.e., idle) wellbores are intersected within the zone contacted by fracturing fluids during the high-pressure stage of injection. Similarly, producing wells in the same target formation as horizontal wells undergoing hydraulic fracture stimulation may be affected by fracture fluids when the inter-wellbore distance is within perhaps 250 m, depending on the size of the hydraulic fracture stimulation. This influence distance may increase if faults or highly permeable channels are intersected.

The potential for natural phenomena to cause gases from depth enter shallow groundwater is related to structural deformation, as shown by several cases where hydraulic fracturing was not involved. For example, Fountain and Jacobi (2000) reported that in western New York, USA, where fault reactivation is suspected, deep thermogenic gases migrated to locations where they were sampled at ground surface. Similarly, Kreuzer and others (2018) contend that faults in Paleozoic rocks elsewhere in New York are responsible for gas and brine migration from depth such that the groundwater quality in shallow aquifers is affected. The use of noble-gas isotopes is essential in confirming these hypotheses. Banks and others (2019) reported linkages between the Gloucester Basin coal seam gas deposits in New South Wales, Australia, and a shallow alluvial aquifer via a deep groundwater baseflow component. They noted hotspots in ^{4}He and the isotopes ^{13}C and ^{2}H associated with methane in nearby fault damage zones, which were associated with discharge of deep groundwater. These were shown to have mechanically sensitive fractures with increased permeability.

3.1.3 Gas Contamination from Wellbores

Hydrocarbon fluids leaking from a wellbore, generally gases, may be from several potential sources, depending on the geological stratification and wellbore location. The fluids may be of deep thermogenic origin, which we define as the general reservoir depth, or from one of potentially several shallow to intermediate depth hydrocarbon-bearing units, in which the gases may be either of biogenic or thermogenic origin, or a combination of both.

The isotopic signature of hydrocarbons can provide evidence of their source, their maturity, and their origin (e.g., Schoell et al., 1993; Rich et al., 1995; Tilley & Muehlenbachs, 2006). Most often, leaking gas is found to originate from a shallow to intermediate depth formation, rather than from the targeted hydrocarbon reservoir. Evidence comes from isotopic analyses using drilling-mud samples from approximately 300 wells in Alberta and British Columbia, Canada (Tilley & Muehlenbachs, 2006).

In the Western Canada Sedimentary Basin, gases in formations associated with heavy oil deposits of the Mannville Group on the Alberta-Saskatchewan border area have distinctive geological histories compared to shales in the overlying Colorado Group. These differences are reflected in their isotopic fingerprints (Figure 17) and were utilized in a study to determine that the gases found in three-quarters of the leaking sampled wells must have originated from a gas-bearing interval located above the heavy oil production zone (Rowe & Muehlenbachs, 1999). Bachu (2017) examined gas leakage from heavy oil and bitumen production around Cold Lake and Lloydminster in Alberta, Canada. He identified the origin of the gas migration as the overlying shales and, in some cases, shallow coal beds, rather than the producing zones.

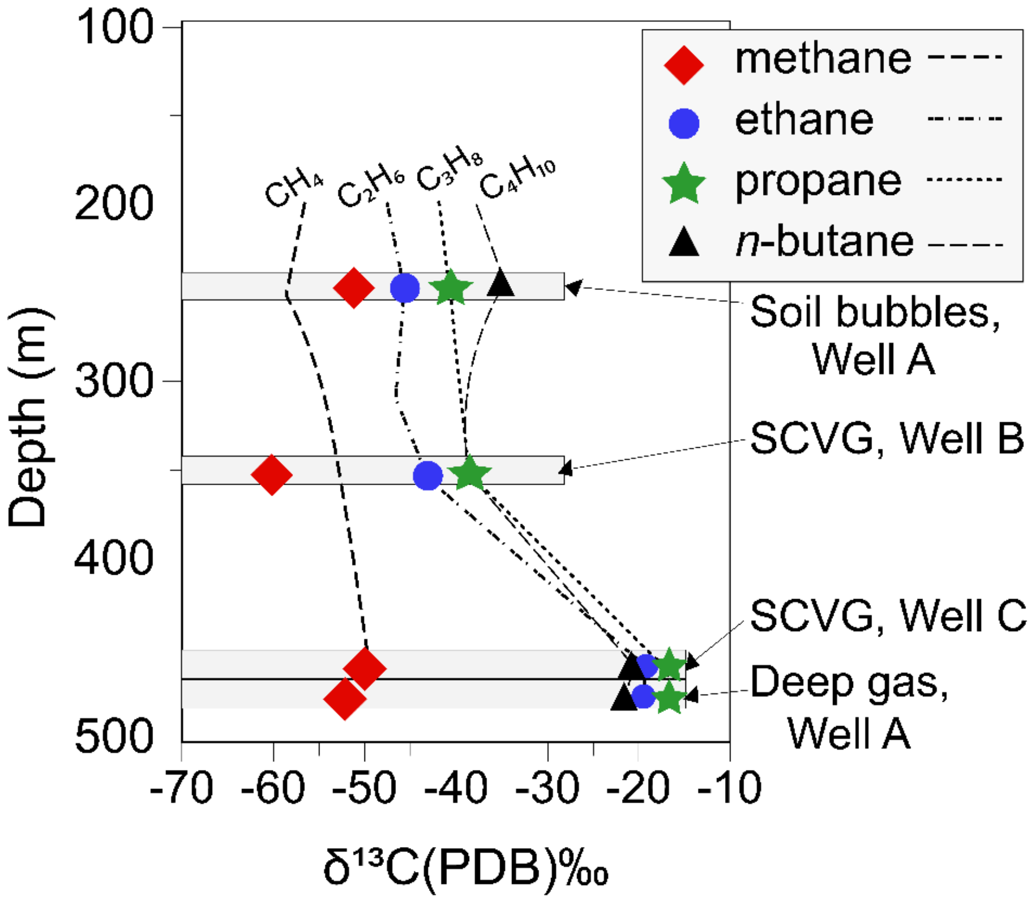


Figure 17 – Black lines show the stable carbon isotopic composition in δ13C per mil (‰) and referenced to the PeeDee Belemnite (PDB) standard determined using mass spectrometry for the major natural gas components—methane (CH_4), ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10})—as a function of depth in the Lindbergh Field, Alberta, Canada. Isotopic fingerprints of drilling-mud samples from approximately 300 wells in Alberta and British Columbia, Canada (Tilley & Muehlenbachs, 2006) clearly identify gases associated with specific sedimentary formations. The stable carbon isotopic fingerprint of two gases sampled at surface casing vents (SCVG, Wells B and C), a sample of soil (gas) bubbles in ponded water around well A, and reservoir production gas from the Cummings formation ("Deep gas, Well A") are shown as colored symbols, plotted at the depth where they best correspond to the isotopic profiles. Each sample differed, allowing investigators to identify the origin of the natural gas sample. The soil bubbles of Well A correspond to the isotopic signature of gas from about 250 m depth, while the vented gas from Well B corresponds to the signature at a depth of about 350 m, and the gas vented from Well C corresponds to gas produced from the Cummings formation (modified from Rowe & Muehlenbachs, 1999).

Unfortunately, despite isotopic fingerprinting being introduced by Schoell and others (1993), few such studies can be found in the journal literature from USA basins. Colorado, USA, however, has made public the geochemical analyses of surface-casing fluids and this allowed Lackey and others (2022) to investigate the nature of wellbore integrity failures in the greater Wattenberg area north of Denver. They determined that the vast majority of surface-casing fluids from oil and gas wells sampled in the Wattenberg field contained thermogenic gas that appeared to be production gas. This gas is presumed to have entered the surface-casing annulus through production-casing failure (or perhaps poor coupling connections) and/or compromised cement seals.

The broad disclosure of data required by the Colorado, USA, and Alberta, Canada, regulatory agencies has revealed two quite separate causes for loss of wellbore integrity. In Alberta, the majority of wellbore annuli had gas that originated in the shallow or intermediate zones of the wellbore, whereas in the Wattenberg Field of Colorado the majority (68%) of the annulus gas was from the production zone. Thus, isotopic signatures of wellbore annulus gases lead to the greater possibility of scientific study and quantitative assessment of wellbore leakage in producing fields.

In addition to the stable isotopes of carbon, oxygen and hydrogen, noble gases and their isotopes have proved to be significant aids in identifying the origin of leaking natural gas in shallow groundwater (Darrah et al., 2014; Wen et al., 2016; Kreuzer et al., 2018; Whyte et al., 2021). Barry and others (2018) and Tyne and others (2021) have demonstrated how the ratio of noble-gas isotopes (e.g., $^{20}Ne/^{36}Ar$) can be used to differentiate between formation fluids and injected enhanced oil recovery fluids in samples recovered from well casings in several Californian (USA) oil fields.

Producing formations are not often the source of an outside-of-casing leak because, as pointed out by Watson and Bachu (2009) and Dusseault and Jackson (2014), these deeper regions are often sealed with the highest quality cement in the wellbore. During placement, the cement at the bottom interval is subjected to high hydrostatic pressure because the cement density is on the order of 1.9 gm/cc (unless special lightweight slurries are used to avoid lost circulation). Because the hydrostatic pressure of the cement slurry when it is fully liquid is significantly higher than the surrounding pore pressure (large Δp), significant amounts of water are lost to adjacent strata that may be somewhat permeable, resulting in a dense cement with a good seal (Dusseault & Jackson, 2014).

Conversely, when intermediate and shallow depth intervals are sealed with cement, this cement is of lower quality with several filler additives that do not always generate good primary wellbore seals (Watson & Bachu, 2009). Intermediate and shallow depth gas sources are typically thin, non-commercial hydrocarbon-bearing formations found in low-permeability sandstones and silts, high-permeability sand seams, or even in coals. Furthermore, in all natural gas plays, including shallow coal-bed methane plays, methane that has risen slowly from depth is found dissolved in formation water in the intermediate and shallow zone.

Intermediate and shallow formations often have fluid pressures at or slightly above regional pore pressure (i.e., typical hydrostatic pressures at the same depth) because gases that were slowly generated by biogenic processes or traveled from a deeper thermogenic source become trapped in these regions. These formations present a significant risk for leakage because if the cement quality is poor, gas can seep into the exterior wellbore annulus (rock-casing annulus) and accumulate through the displacement of water (Saponja, 1999). Microannuli (thin annuli between cement and rock or cement and casing) can develop in intermediate and shallow formations and provide pathways for gas migration. Gas flow through microannuli has been simulated in the laboratory and the results analyzed to show that even if large confining stresses are applied, the microannuli "remain open and capable of conveying significant flow" (Stormont et al., 2018, p. 11). In contrast, deeper reservoir sources become zones of low regional pressures because they are depleted as a result of production and, "…depleted shale gas formations become a zone of low regional pressure and are more likely to induce brine flow into it than to allow gas flow to escape" (Dusseault and Jackson, 2014, p. 116).

The poor displacement of drilling fluids during well completion, combined with using inadequate cement densities, may result in the development of microannuli or channels and generally poor cementation quality. In addition to incomplete borehole cleaning and inadequate mud displacement issues, microannuli develop in large part because of autogenous shrinkage leading to reduced radial stresses and poor cement bonding with the adjacent rock (Watson, 2004). Insufficiently dense cement slurry can cause these issues and result in poor cement contact with the rock face that is easily ruptured (Bentz & Jensen, 2004; Bois et al., 2011; Boisnault et al., 1999).

Cement requires water-wet clean surfaces for cohesive bond development and will not bond with materials such as salt, oil-rich beds such as oil sands, high porosity shale, and drilling mud filter cake (Dusseault et al., 2000). In addition, if residual mud remains on the casing or borehole wall, a stable long-lasting cement bond will not form (Zhang & Bachu, 2011). This inhibits attainment of *zonal isolation* of the producing formation from shallower formations that may not have gas in commercial quantities.

Failure to isolate the non-commercial shallow and intermediate formations with adequate cement sealing may allow free gas to rise to the ground surface via the annulus around the wellbore—i.e., behind the casing—because of its buoyancy in water. It is well established by noise logging of boreholes that gas slugs rise behind the casing and that the nature of the buoyant rising gas can be identified by the noise frequency (Dusseault & Jackson, 2014). The origin of most (if not all) gas slugs observed at ground surface is one or more gas bubbles released at depth behind the casing (or, in some cases, from within the casing through leaky casing couplings). Hence, periodic slugs of gas may be released within a borehole, travel up the annulus driven by buoyancy, and migrate from the wellbore into the surrounding soil and/or rock under pressure.

Several researchers have estimated the effective permeability of leaking legacy wells. Gasda and others (2013) reported results from three vertical interference tests yielding annular permeabilities of 1.7, 25, and 170 mD (1 mD = 10^{-15} m^2) but suspected that much higher permeabilities might be found due to other data examined. Kang and others (2015) estimated an effective permeability of 10^{-6} to 10^{2} mD (10^{-21} to 10^{-13} m^2) within and around 42 plugged and unplugged abandoned wells in Pennsylvania. The comprehensive review by Alberdi-Pagola and Fischer (2023a) concluded that a competent cement sheath would have an effective permeability <10^{-17} m^2, i.e., < 10^{-3} mD. They reported effective permeabilities in the range 10^{-17} to 10^{-12} m^2.

To enter the adjacent water saturated soil or rock the gas pressure in the wellbore (P_{gas}) must be sufficient to overcome the pore water pressure in the soil or rock ($P_w = \rho gh$, where ρ is the fluid density, g is the acceleration of gravity, and h is the height of the column of fluid) plus the capillary entry pressure (P_e). If gas starts to flow into the soil or rock it will continue to do so until the gas pressure is reduced to the point where it cannot overcome the capillary barrier, i.e., when $P_{gas} < P_e + P_w$. However, as gas-slug generation continues downhole, the gas pressure will build again until pressure is sufficient to further displace water in adjacent formations. This leads to gas entering the adjacent formation as pulses. If there is a sufficiently large source of gas to maintain the pressure, then the flow of gas through the soil or rock will be essentially continuous.

Lackey (2024) presented three scenarios, shown in Figure 18, where well integrity monitoring programs provide insight into leakage that is suggested by sustained casing pressure at the wellhead. From left to right, the scenarios a, b, and c shown in Figure 18 illustrate the following.

a) Gas migration may arise from depth along fractures in the cement annulus surrounding the production casing or up microannuli in the cement annulus (Dusseault & Jackson, 2014).
b) Some of the upward migrating gas may migrate into a preferential pathway in the surrounding rock, as also shown in Figure 13. In the case shown in Figure 13, the origin of the gas is a deep formation – perhaps a marginal gas producer – above the production zone.
c) If the surface casing is fully pressurized, then the sustained pressure may induce gas migration into shallower sediments and aquifers. Depending on the pressure within the production tubing and the adjacent intermediate-zone rock, gas may escape the production tubing through casing fractures or leaky couplings or enter it by invasion from the intermediate zone of the well.

The three scenarios shown in Figure 18 should form part of the basis for wellbore integrity monitoring by regulatory agencies.

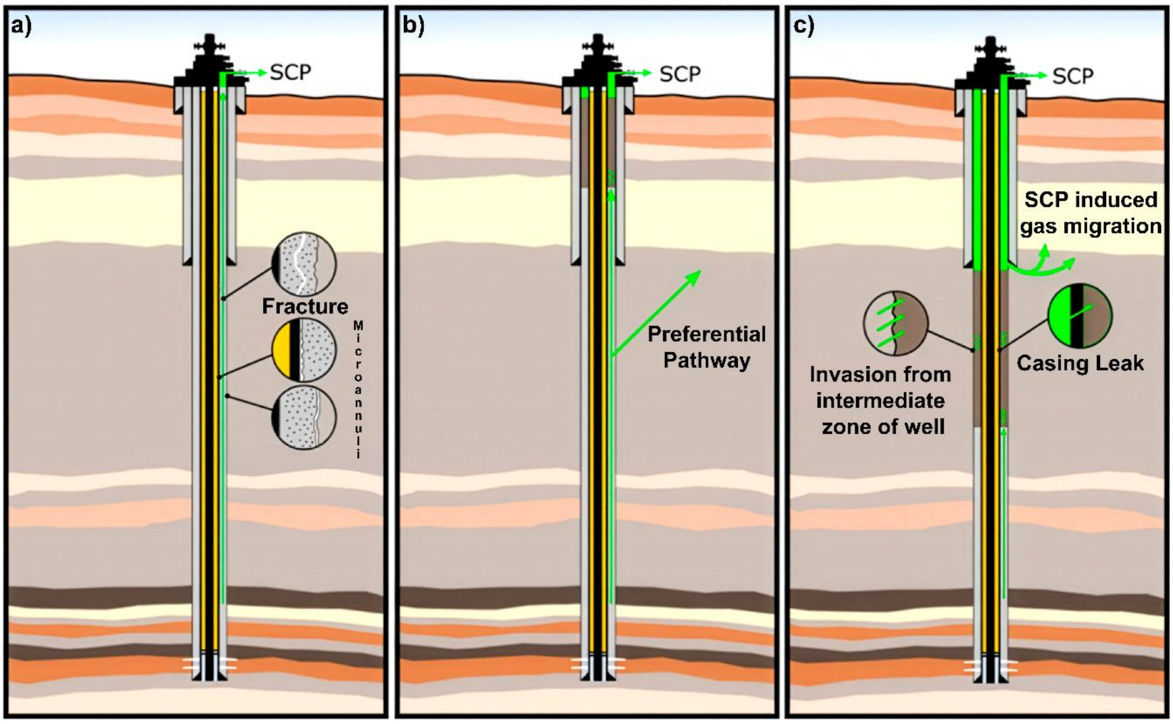


Figure 18 - Wellbore integrity programs can provide insight into leakage that may affect groundwater. This leakage can be caused by the borehole conditions shown in a), b), and c) together with sustained casing pressure (SCP). The text provides further explanation. In a), microannuli are the thin white lines between the cement and the production casing and between the cement and borehole wall (adapted from Lackey, 2024).

3.2 Key Regulatory Considerations

In this section we consider regulatory issues of considerable importance to gas migration into shallow aquifers. The first is the operation of the surface casing vent valve, otherwise known in the USA as the *bradenhead*. The others include the regulatory requirement for drillers to allow a *set-back distance* or separation interval between the drill pad and the nearest water supply wells; cementing requirements; and urban encroachment on oil and gas fields. Regulatory requirements vary from jurisdiction to jurisdiction, consequently the websites of the appropriate regulatory agency must be consulted for details.

3.2.1 Surface Casing Venting

The problem of gas buildup behind the casing, i.e., between casing and the bedrock wall as shown in Figure 18, was first documented in the hydrogeological literature by Harrison (1985) and subsequently by Chafin (1994) and Van Stempvoort and others (2005). This issue had long been known to petroleum engineers seeking to reduce losses from production wells (Cooke, 1979; Cooke et al., 1983). A recent review by Hammond and others (2020) of several USA case histories of groundwater contamination concluded that the "…most common cause of incidents was the presence of uncemented sections of production casings in wells that allowed gas migration from intermediate depths to shallow freshwater aquifers" (p. 1481).

Whether gas flows to the wellhead because of an absence of primary cementing—as shown in Figure 13—or a poor cement job that has allowed flow pathways to form in the cemented casing (Figure 18a), the gas will either discharge to the atmosphere via an open surface casing vent or be trapped by the shut-in surface casing head (i.e., the *bradenhead*). It is common practice in USA jurisdictions that the casing head be shut in, which results in pressurized gas accumulation within the surface casing annulus and eventual gas migration around the base of the surface casing and into adjacent aquifers, as shown in Figure 13. It is Canadian practice that the surface casing gases be vented to prevent such gas build-up, allowing atmospheric release of surface casing gas. If the surface casing vent flow is sufficiently high, remediation of the vented gas is required.

An example of problematic gas build-up caused by a shut-in casing head appears in an article describing the contamination of domestic wells in the Marcellus Shale play in Pennsylvania, USA (Llewellyn et al., 2015). The authors describe groundwater contamination occurring over horizontal travel distances of about 1 to 3 km by migration along shallow- to intermediate-depth fractures. Moreover, they indicate that leaky gas wells with excessive annular pressures are likely to blame for methane-contaminated wells (Llewellyn et al., 2015). An additional possible contamination source in this study was seepage from a wastewater pit, where flowback fluids were stored, that may have accounted for components of fracking fluid identified in one contaminated water well.

Whereas lateral gas flow through shallow bedrock is quite common near leaky USA gas wells, it should not be assumed that long-distance gas migration will not occur in those jurisdictions where gas venting from surface casings is permitted or mandated—e.g., Canada. In Alberta, where oil- and gas-well regulations are comprehensive in scope and detail, "…the existing policy framework, which dictates how SCVF [surface casing vent flow] and GM [gas migration] are tested, are inadequate to appropriately quantify methane emissions" (Abboud et al., 2021, p. 49).

The sustained pressure that builds up within the surface casing is referred to as *surface casing pressure* by the industry and can be tested by the API Surface Casing Pressure test protocol (API, 2016), which is required in some USA states. This annular pressure can be measured at the wellhead and, if considered dangerously high, it can be bled off. If the annular pressure builds up again, remedial action can be taken to seal the formations that are leaking gas. This pressure bleed-down and pressure-buildup test can therefore identify wells with poor well integrity. Lackey and others (2021) discovered that 14% of wells in Pennsylvania tested before 2018 had sustained casing pressure.

In their assessment of well integrity in the Wattenberg gas field in Colorado, USA, Lackey and others (2017) identified the critical surface casing pressure (SfCP) as that which would cause "annular liquids below the bottom of the surface casing" to be displaced into the adjacent formation, i.e., the strata at the shoe of the surface casing, (Lackey et al., 2017, p. 3570) assuming no annular cement is present. As they pointed out, the absence of cement is a necessary but insufficient condition for penetration of the adjacent formation because for this to occur, the annular liquids must exceed the entry pressure of the formation (capillary pressure plus pore pressure), a criterion that the critical SfCP includes.

If open fractures coincide with the depth of the surface-casing shoe, then the fractures would be readily penetrated because their capillary entry pressure would be close to zero. In this case, Lackey and others (2017) suggest that the critical SfCP=$\rho_w g H_w$, where ρ_w is the density of the groundwater, g is the acceleration due to gravity, and H_w is the height of the potentiometric surface above the casing shoe in the annulus. In simpler terms, gas pressure must only exceed water pressure to displace water if there is no capillary entry pressure. However, a porous rock matrix might not be so readily penetrated, as the capillary entry pressure (P_e) plus the pore pressure would have to be exceeded. The entry pressure of a rock matrix can be determined from a mercury injection capillary pressure test with the capillary pressure adjusted for gas-water interfacial tension and contact angle values (instead of air-mercury values). Lackey and others (2021) identified that 3% of Colorado, USA, wells tested between 2005 and 2009 exhibited SfCP sufficient to cause gas migration beyond the well.

A section of the Berea sandstone became contaminated by a leaky gas well in Bainbridge Township, Ohio, USA, (Bair et al., 2010) because open fractures allowed gas to migrate into residential wells. The shut-in pressure within the gas well was 320 psi (2.2 MPa), which was sufficient to penetrate both the sandstone fractures and the rock matrix. Because the Berea sandstone is a well-known test formation for which mercury capillary injection results are widely published, the sandstone-matrix entry pressure is estimated at <2 psi (14 kPa); the fracture entry pressure would be even less. In terms of capillary entry pressures, this is near zero. The sum of capillary entry and hydrostatic pressures would be <400 kPa at the relatively shallow depth of the Berea sandstone at 38 m. Consequently, both fractures and matrix within the Berea were readily contaminated. Bair and others (2010) report that it required seven months of over pumping the domestic wells to remove the contaminating gas phase.

3.2.2 Set Back Distances

The noise, dust, and traffic that are associated with drilling and completing energy wells has resulted in most affected jurisdictions mandating a minimum *set-back distance* between a drilling operation and homes and other places of human occupancy or work. Typically, the setback is at least 400 m (0.25 miles) and often on the order of 1 km (0.6 miles) or more.

Regarding set-back distance with respect to water supply wells, given their experience with fugitive gas migration, R.B. Jackson and others (2015) recommended that baseline and post-fracking testing of groundwater quality should occur "to a radius of at least 1000 ft (~350 m) beyond the greatest extent of horizontal drilling from the oil or gas well" (p. 8975). Given the typical lengths of horizontal wells, this may mean that a set-back distance might be several radial kilometers from the well pad or the set-back distance could be defined relative to the terminus position of horizontal wells. A difficulty with the latter approach is that the position of the terminus of the well is not readily apparent from the surface, thus it would be difficult to enforce.

3.2.3 Well Cementing

Preventing or reducing the incidence of gas migration from oil and gas wells necessitates establishing regulatory practices that require careful and complete primary cementing of the well-casing annulus to prevent gas migration up the annulus. The operator responsible for the well should undertake due diligence to understand the location of water supply wells, abandoned oil and gas wells and producing wells to prevent inter-wellbore communication.

3.2.4 Urban Encroachment

While regulatory protocols are important, they are quite irrelevant when urban areas encroach on old oil and gas fields. Many cases in the Los Angeles Basin of southern California, USA, have been documented by Chilingar and Endres (2005). Gas migration beneath a new school building site in downtown Los Angeles above a depleted oil field was reported in detail by Kaplan and Sepich (2010). New school buildings were demolished, perhaps without good reason, because methane and hydrogen sulfide gases were detected in deep soil samples.

The potential for gas explosions in confined spaces and gas emissions into homes, factories and public buildings is real. These problems of urban encroachment exist across North America and to some extent in Europe. The health hazard is more severe when the natural gas includes hydrogen sulfide, which is present in "*sour gas*", and may also be produced in shallow sulfate-bearing soils and groundwater by anaerobic methane oxidation and sulfate reduction. Careful regulatory mapping of old oil and gas fields is required to safeguard public health and property.

3.3 Climate and Air Quality Impacts

Emissions of methane, other hydrocarbons (e.g., ethane, propane), carbon dioxide, and hydrogen sulfide have been observed at active and abandoned well sites and facilities. These gases may be emitted due to degassing from pumped groundwater, subsurface gas migration to the ground surface, and through processes that are not related to subsurface gas migration, such as gas storage tank operations and equipment venting. Here, we describe the climate and air quality impacts of gas emissions without specific reference to a source—which can be difficult to identify in many cases, as described later.

Methane and carbon dioxide are primary greenhouse gases responsible for the vast majority (~90%) of anthropogenic emissions (US Environmental Protection Agency, 2019).

Methane is a strong greenhouse gas with a global warming potential of 84 times that of carbon dioxide over the first 20 years of its release and a warming potential 28 times larger over a century (IPCC, 2014). Although carbon dioxide represents the largest share (~80%) of anthropogenic greenhouse gas emissions, methane is of primary concern for the oil and gas industry because in many countries—including the USA and Canada—oil and natural gas systems are the largest sources of anthropogenic methane emissions.

Methane in the atmosphere is a precursor to tropospheric ozone formation, which degrades air quality as well as human and ecosystem health (West et al., 2006). Volatile organic compounds including aromatics (such as benzene, a known carcinogen) also degrade air quality (Piccot et al., 1992) and have been found to be emitted from oil and gas production sites (Pétron et al., 2014).

Hydrogen sulfide is a highly toxic gas with a recommended exposure limit of 10 ppm. It can pose an immediate danger to human and ecosystem health at concentrations of 100 ppm and above (NIOSH, 2014). Because of the well-known impacts of acute (short-term) high-concentration hydrogen sulfide exposure, the oil and gas industry has developed training certification programs, personal protective equipment such as personal gas monitors and self-contained breathing apparatuses, and safety and evacuation protocols. However, the role of chronic low-level exposure to hydrogen sulfide on the central nervous system and respiratory functions, especially for vulnerable populations, remains inconclusive and requires further study (Lim et al., 2016). For those living near legacy wells that emit hydrogen sulfide, such as in southern Ontario, Canada, (El Hachem & Kang, 2022), the effect on their health is poorly understood although the deterioration in their property value is measurable.

4 Forensic Examples from the Field

In Section 4 we discuss examples from forensic studies. First, we consider the nature of documented cases of groundwater contamination by oil and gas operations, whether locally around a well pad from spills and leaks or from the migration of natural gas caused by wellbore leakage. We also summarize evidence for the in-situ biodegradation of methane that indicates these natural gas emissions tend to undergo natural attenuation. Second, cases of methane emissions to the atmosphere are described based on measurements conducted at local to regional scales.

4.1 Groundwater Contamination

The intent of section 4.1 is to summarize the forensic evidence of groundwater contamination associated with oil and gas operations and the effects contamination may have on groundwater quality. The contaminants may be petroleum, natural gas, or brine associated with their production; it may be fuel, chemicals, or fracking fluids deployed at the well pad during drilling and completion operations. The section begins with evidence of groundwater contamination from well-pad operations and then considers the evidence of contamination from gas migration associated with poorly or incompletely cemented wells. It concludes with a review of evidence of in-situ biodegradation of petroleum and natural gas.

4.1.1 Contamination at the Well Pad

The literature on well-pad contamination of groundwater is limited in the USA, probably because the oil and gas industry was omitted from direct regulation by the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) in 1980. CERCLA, which created the USA Superfund cleanup program, allowed an exclusion for "petroleum, including crude oil or any fraction thereof" unless that fraction was specified in the Act. Thus, it was other liquid substances that were considered hazardous—such as chlorinated solvents and pesticide residues—that were subject to hydrogeological site investigations and research. In addition, drilling waste is exempt from the Resource Conservation and Recovery Act (RCRA) (US Environmental Protection Agency, 2025).

Few studies of contamination by oil-field operations were published in the twentieth century. Pettyjohn (1982) and Novak and Eckstein (1988) looked at brine contamination of aquifers from surface impoundments. Lyverse and Unthank (1988) described leaking abandoned oil and gas exploration wells that polluted nearby municipal supply wells. One topic that was not ignored in the twentieth century was that of petroleum contamination following a pipeline breach. It was intensely studied over a period of 25 or more years by the United States Geological Survey (USGS) at the Bemidji site in Minnesota, as summarized by Essaid and others (2011). They demonstrated that spilled petroleum was subject to a variety of attenuation and transport mechanisms that are likely to exist at any well-pad site contaminated by a crude oil spill. Subsurface attenuation processes are particularly important, including hydrocarbon degradation and emission as CO_2 (gas) diffusion through the vadose zone (Lundegard & Johnson, 2006; Sihotra & Mayer, 2012), are particularly important.

Studies of contamination from oil and gas operations became more prevalent in the twenty-first century. Lauer and others (2016) reported that between 2007 and 2016 there were ~3900 spills of produced water and other wastewater reported to state regulators during the drilling of ~9700 unconventional oil wells in the Bakken play of North Dakota. These spills occurred primarily during transportation of the produced brine to injection wells, where the water is disposed in deep confined formations. Spills occurred at various stages of wastewater handling from storage facility operations to truck or pipeline delivery. Lauer and others (2016) reported that the inorganic contaminants were remarkably persistent as might be expected in the soils of this semi-arid region. Consequently, such incidents pose threats to shallow groundwater. However, contamination related to oil field operations was largely ignored until 2009–2010, when concerns about well-pad practices and the fate of wastes generated in the Marcellus Shale play resulted in scientific inquiry (Maloney & Yoxtheimer, 2012; Considine et al., 2013).

Because the viscosity of petroleum limits its migration rate and distance (Jackson et al., 2006), the greater concern about contamination at well pads arises from the leakage of produced water from lagoons or stored fracking fluid. Even where brine is contained within a lagoon underlain by a compacted clay liner, seepage through such a liner has been observed in monitoring wells adjacent to the brine pond, showing migration of chloride with concentrations greater than 1,000 mg/L (Folkes, 1982). Unlined produced-water ponds are also source of groundwater contamination, as in the Central Valley of California where DiGuilio and others (2021) discovered from sparse groundwater-monitoring records that high levels of benzene, boron and chloride can infiltrate from such ponds into regional aquifers. Tailings ponds in the Athabasca Oil Sands, Canada, rely on seepage management systems and the low permeability of the till and clay on which the numerous ponds are built. Fennell and Arciszewski (2019) found evidence of considerable groundwater contamination from the ponds but not of surface water contamination.

A few cases of groundwater contamination that originate at the well pad were identified in studies of contamination during production of the Marcellus Shale gas play. Llewellyn and others (2015) hypothesized that there was some evidence of hydraulic fracturing components that had contaminated water wells in the Marcellus Shale gas play either by a reported *drilling fluid pit leak* or by flow up the annulus of one or more new gas wells following fracking. These components followed a pathway in the shallow bedrock like that shown in the fracture zone in Figure 13.

Drollete and others (2015) reported a study of shallow groundwater above the Marcellus Shale that "determined that the dominant source of organic compounds to shallow aquifers was consistent with surface spills of disclosed chemical additives" (p. 13184). These include components of hydraulic fracturing fluid, and of diesel and gasoline hydrocarbon derivatives. Thus, surface spills of fracking fluids and fuels appear to be a significant source of contamination in shallow groundwater tapped by water wells; this is hardly surprising and not confined to oil and gas development.

Van Stempvoort and others (2024) investigated hydraulic fracturing chemicals as potential tracers of groundwater contamination. They determined that low molecular weight polyethylene glycols displayed low sorption potential and were quite persistent in simulated groundwater conditions. These glycols therefore show promise as fracking-fluid tracers that might be detected in groundwater even after dilution of ~3000 to 3,000,000-fold.

4.1.2 Contamination Caused by Drilling Processes

Rotary air drilling may initiate groundwater contamination in areas with shallow bedrock methane that occurs naturally. On the morning of January 1, 2009, in an incident that became an icon of the perceived hazards of fracking, the well vault of resident Norma Fiorentino exploded outside her house near Dimmock, Pennsylvania (Figure 19). The most likely cause was *fugitive natural gas*, either naturally present or associated with gas wells drilled in the Marcellus Shale gas play (Wilber, 2012). Public media, however, tended to associate the problem with hydraulic fracturing rather than poor primary well cementing; for example, the Gasland documentary video released in 2010 greatly contributed to this misperception and contributed to anti-fracking social mobilization (Vasi et al., 2015).

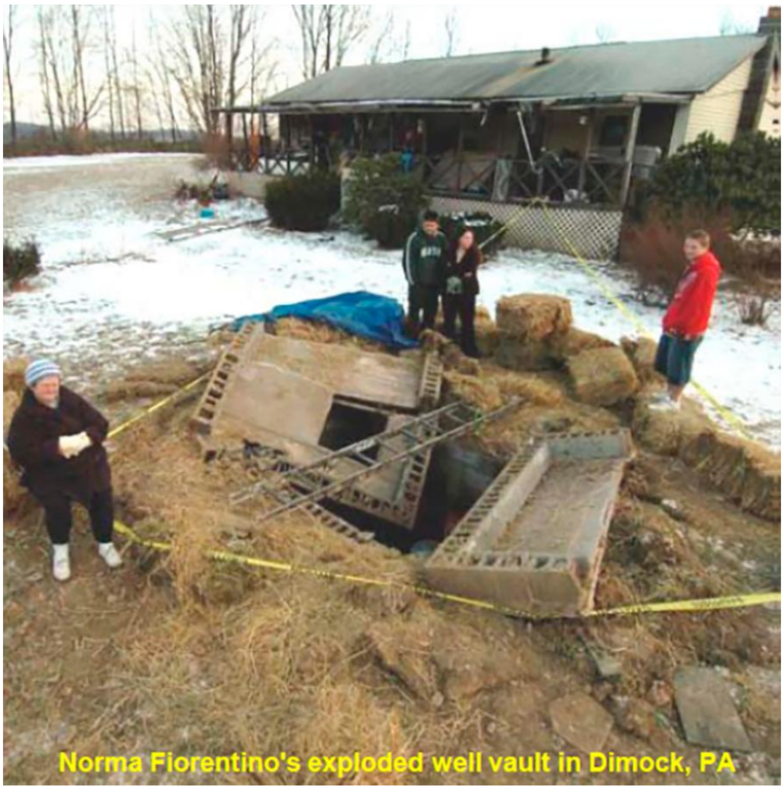


Figure 19 - An exploded water-well vault near drilling operations in the Marcellus Shale gas play, Dimmock, Pennsylvania, January 1, 2009 (adapted from Soeder, 2012).

The origin of the fugitive gas that caused the damage shown in Figure 19 was probably the displacement of gas naturally present in shallow fractured bedrock by the high-pressure air used in air rotary drilling operations during shale-gas development (Geng et al., 2013). The concept is presented in Figure 20, which emphasizes the presence of naturally occurring methane in the shallow bedrock. In some jurisdictions, air drilling or aerated fluid drilling can take place to depths of 1000 m if the formations have sufficient compressive strength (i.e., are "strong rocks") and if there are no hydrocarbons present in shallow layers that could increase drilling risks. Exercise 3⤵ provides an opportunity to explore the conditions for gas in an annulus space to leak into a formation.

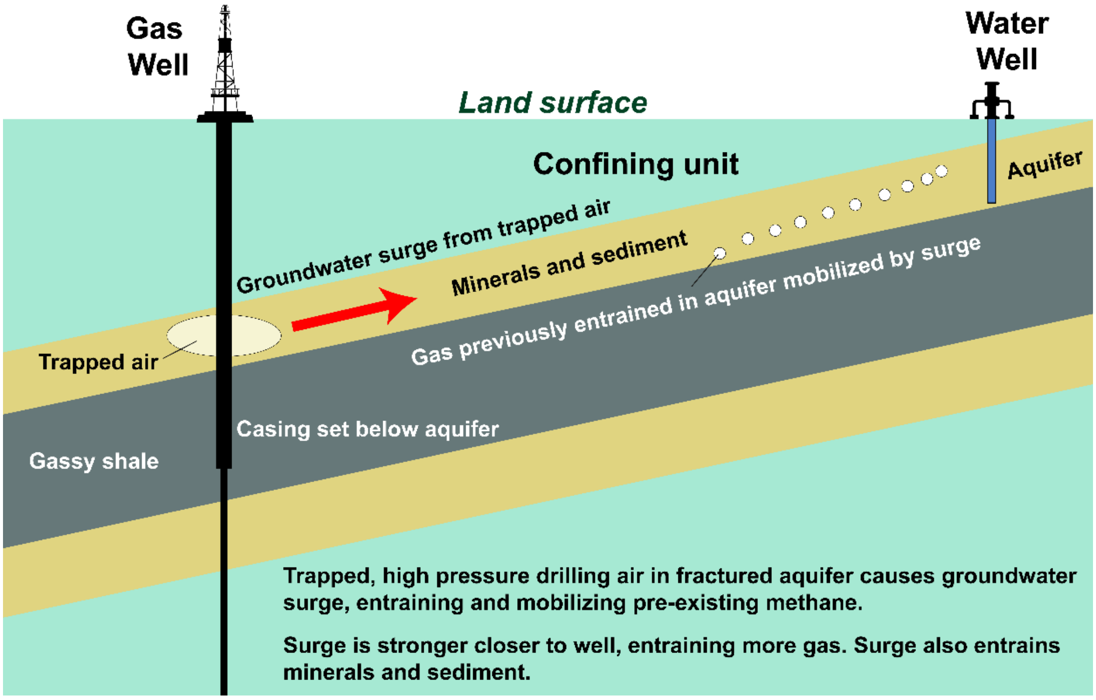


Figure 20 - The probable cause of the exploded well vault shown in Figure 19 (Adapted from Soeder, 2012).

4.1.3 Natural Gas Migration from Leaky Wells

Fugitive methane that travels along wellbores may contaminate freshwater and brackish aquifers. Descriptions of groundwater contamination associated with wellbore leakage have been provided by hydrogeologists beginning with Harrison's (1985) investigations in Ohio. Further, Chafin's study in the USA Southwest coal-bed methane development produced clear evidence that "gas-well annuli are more important than natural fractures for upward migration of gas" (Chafin, 1994, p. 52). The knowledge of wellbore annular leakage of natural gas had, in fact, been documented in the oil industry in the 1950s when attempts were made to detect the location of the leaking zones (Enright, 1955). By the 1970s, Exxon was employing wireline noise-logging tools in the field to identify the movement of fluids in annuli (Cooke et al., 1979; McKinley et al., 1973).

The first fugitive gas paper by the Duke University research team (Osborn et al., 2011) had been inferred by some to suggest that the methane they sampled in shallow water wells was caused by hydraulic fracturing. In fact, a careful reading of Osborn and others (2011) indicated that the Duke University research team "found no evidence for contamination of drinking water samples with deep saline brines or fracturing fluids" (p. 8172).

Later work by the same team (Darrah et al., 2014; Jackson, 2014) indicated that the fugitive gas detected was associated with annular gas flow from shallow gas-rich formations. Hammond (2016) showed that the fugitive gas in the Dimmock area of Pennsylvania was thermogenic gas from intermediate-zone bedrock and not from the deeper hydraulically fractured Marcellus Shale. In some wells, the cement forming the annular seal between the outer casing and the wall of the borehole was either not emplaced during primary cementing or was not completed with sufficient care, consequently the fugitive gas escaped up the wellbore annulus (Dusseault & Jackson, 2014). In the Denver-Julesburg Basin of Colorado, USA, Sherwood and others (2016) identified 42 water wells that contained thermogenic production-zone gas that they believe was caused by either the inadequate length of the surface casings of production wells, casing leaks, or cement failures. The potential seepage pathways for natural gas to the ground surface are summarized in Figure 21, which also shows potential sources of groundwater contamination from well pad operations.

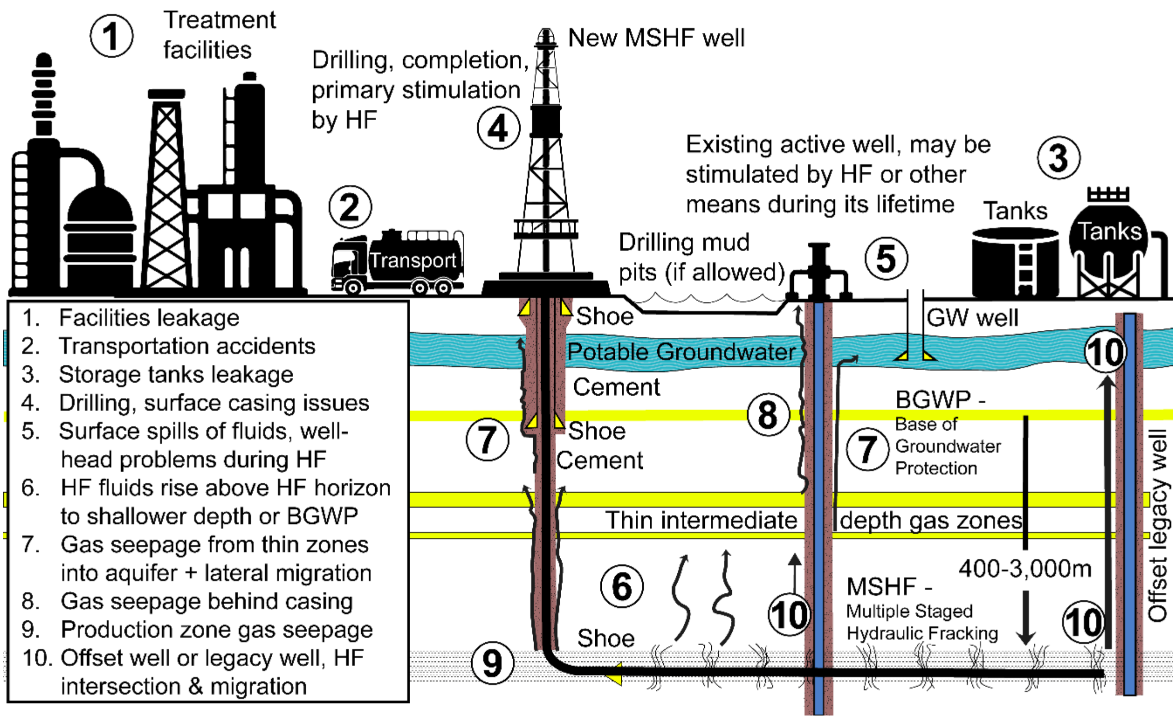


Figure 21 - Potential sources of groundwater contamination from well pad operations (items 1 to 5) and potential pathways by which fugitive natural gas might migrate to the ground surface (items 6 to 10). HF is hydraulic fracturing. MSHF is multiple staged hydraulic fracturing. BGWP is base of groundwater protection.

How far might fugitive gas migrate in the shallow subsurface? The answer depends on the permeability of the shallow bedrock and surficial sediments and the gas pressure at the source of the leak. The following three USA case histories provide some insight into lateral migration.

- **Hutchinson, Kansas:** In January 2001, explosions occurred in downtown Hutchinson followed by burning buildings and geysers of water spewing up to 10 meters above surface from abandoned brine wells. The fire department reported that at the end of day, the flames would not die out. An abandoned brine well exploded the next day beneath a mobile home killing two people (Allison, 2001). The origin of the gas was identified as a gas storage cavern, which was 10 km from downtown and 14 km from the mobile home site. The gas pressure in the casing leak above the gas storage cavern was ~4.4 MPa. The migration pathway (Figure 22 and Figure 23) was a half meter-thick zone of fractured dolomicrite at a depth of 140 m at the gas cavern site that rises along the crest of anticline to a depth of 80 m beneath the city of Hutchinson. The maximum gas pressure within the fracture zone exceeded 1 MPa; the permeability of the fracture was estimated to be in the range of 46 to 460 darcies (Watney, Nissen, et al., 2003; Watney, Byrnes, et al., 2003). This is an extremely high permeability, given that oil and gas reservoir permeabilities are typically on the order of 0.01 to 0.1 darcies.
- **Bainbridge Township, Ohio:** In December 2007, fugitive gas from a recently fracked gas well in a suburban neighborhood in northeastern Ohio caused an explosion in a nearby residence and a waterspout 5 m high from one of the neighborhood's water wells. An expert panel of researchers from local universities was assembled to assess the cause (Bair et al., 2010). It was determined that inadequate cementing across a gassy porous dolomite allowed natural gas to migrate up the wellbore annulus and penetrate the Berea Sandstone freshwater aquifer (Figure 24). The gas pressure beneath the casing head was measured at 320 psi, about 2 MPa. At such pressures, gas penetration of the Berea Sandstone matrix was to be expected given the very low capillary entry and hydraulic pore pressure. Over-pumping of the aquifer for a period of seven months cleaned up the contamination.
- **Sugar Run, Pennsylvania:** While the Marcellus Shale gas play was a catalyst that fueled interest in the natural-gas industry, little scientific research has been conducted to reveal the gas migration processes involved until later. Llewellyn and others (2015, p. 6325) observed that gas migration that occurred up-dip from newly completed gas wells over distances of "~1 to 3 km along shallow to intermediate depth fractures" caused water-well contamination. Annular pressures in these wells ranged from 3.3 MPa to 6.4 MPa, which far exceeded the Pennsylvania state regulation of 2.4 MPa.

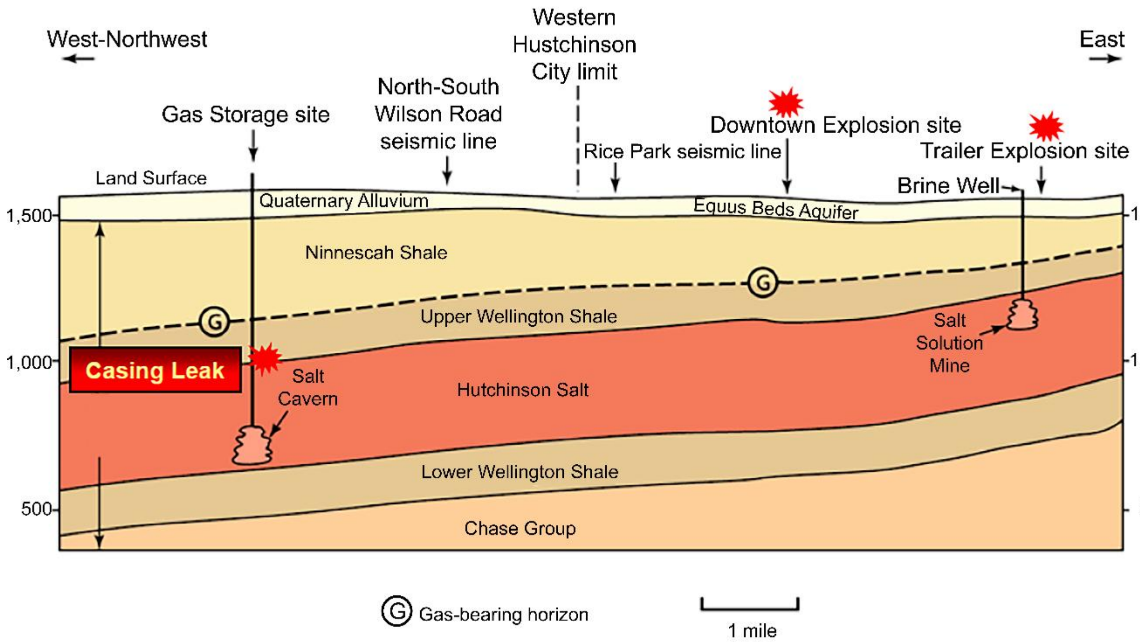


Figure 22 - Cross section identifying a gas bearing horizon near Hutchinson, Kansas, USA. Gas stored in the salt cavern was released through a casing leak at a pressure of ~4.4 MPa. Estimated migration pressures were less but remained above 1 MPa (modified from Watney, Nissen, et al., 2003; Watney, Byrnes, et al., 2003). The elevation units on the ordinate axis are in feet above mean sea level. 1 foot is ~ 0.3 m.

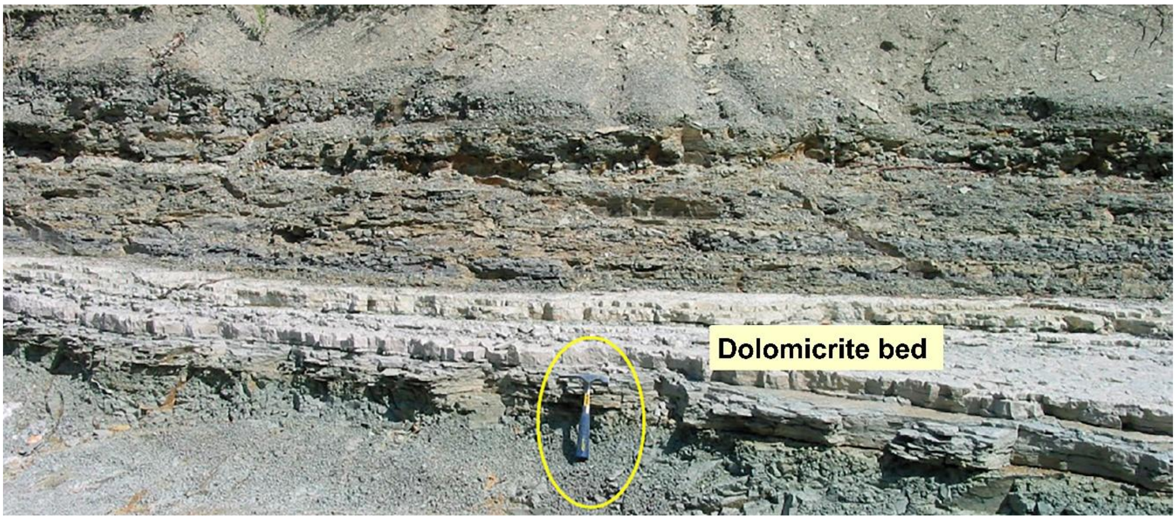


Figure 23 - Gas migration occurred in three thin (<1 m thick) beds of dolomicrite overlying the upper Wellington shale and followed the crest of an anticline in joints in the dolomicrite. Rock hammer shows scale. (photo taken at Afton Lake spillway, Sedgwick County, Kansas, USA; Watney, Byrnes, et al., 2003).

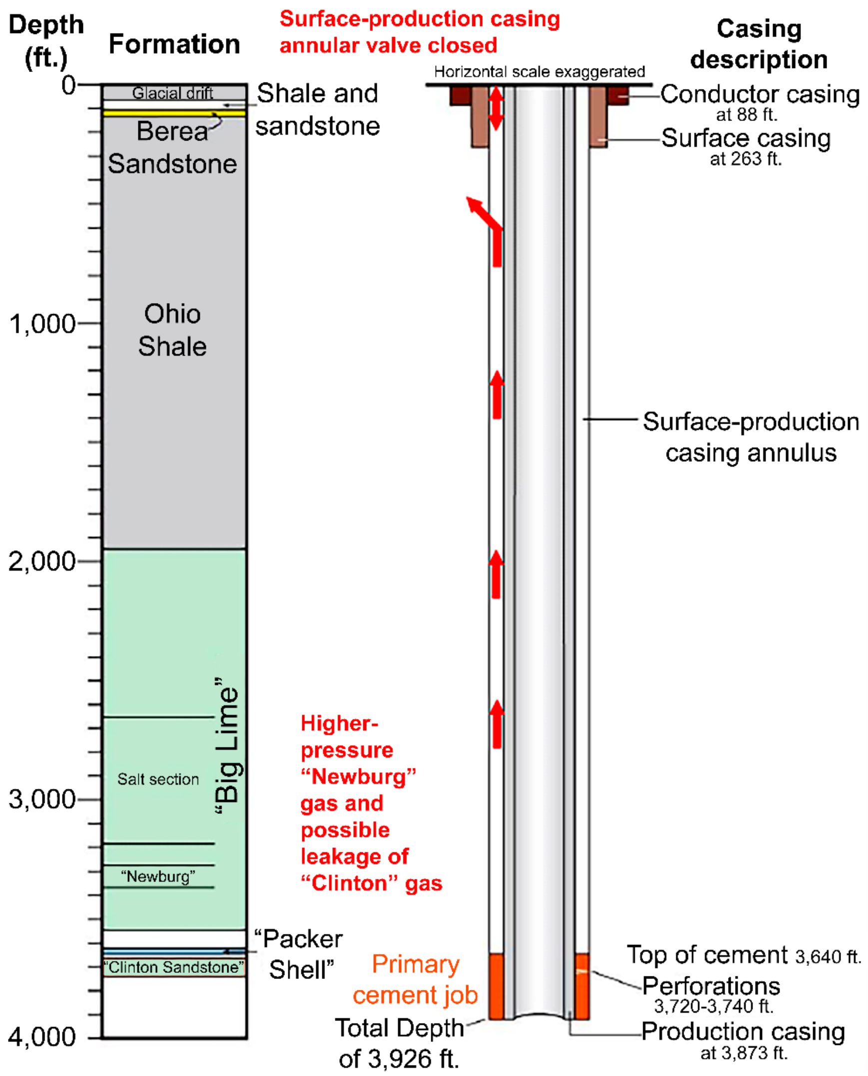


Figure 24 - Wellbore schematic for the English No. 1 Well in Bainbridge Township, Ohio. The "top of cement" of this gas well was only 80 ft [24 m] above the production zone (not 600 ft [180 m] as required by regulation) so that most of the annular space in the well was open to gas flow. High pressure gas was detected in the Newburg dolomite, which was open such that gas flowed into the annulus. The gas well was hydraulically fractured at 1130 m (3707 ft) with no evidence of out-of-zone fracturing; however, oil was observed at the ground surface during stimulation. The casing head was shut in for 31 days resulting in a Bradenhead pressure of 2 MPa. The Berea sandstone aquifer at 38 m bgs is the local groundwater supply and approximately six water wells completed in the Berea were contaminated by the natural gas leak (figure and data adapted from Bair et al., 2010). 1 ft. ~ 0.3 m.

All these cases indicate the hazard posed under the following conditions in uncemented or poorly cemented gas-wells.

1. High gas pressures (> 1 MPa) occurring in uncemented or poorly cemented gas-well annuli.
2. Connection of these annuli to open fractures or permeable formations with low capillary entry pressures.
3. Buoyant gas flow updip within a permeable formation or open fracture network, contaminating nearby water wells.
4. A gas source with sufficient volume and pressure to drive gas for long distances.

From kilometer-length gas migration incidents, Moortgat and others (2018) concluded that such conditions are met if there are very high subsurface gas leakage rates and favorably oriented geologic structures through which the gas can migrate.

However, not all legacy oil and gas wells are pressurized, nor emit CH_4 at high gas pressures. Recent forensic analysis in western Canada has shown that poor well completions led to significant gas emissions at the ground surface ("effluxes") surrounding these wells. For example, Forde and others (2019c) investigated the migration distance of fugitive gas in the vadose zone in British Columbia (Figure 25) and reported that 15 of 17 gas wells showed evidence of CH_4 and CO_2 effluxes measurable by soil-gas chambers sited around the wells. The migration distances varied, but it was found that for 10 of the 17 wells CH_4 emissions were likely to occur > 10 m from the wellhead as they were to occur < 5 m from the wellhead. At five of the wells, the highest effluxes were measured within five meters of the well itself. These authors (Forde et al., 2019c) noted that the low permeability glaciolacustrine soil cover may have caused the gas to migrate further from each leaky well than otherwise would have been the case because it acted as a barrier to flow.

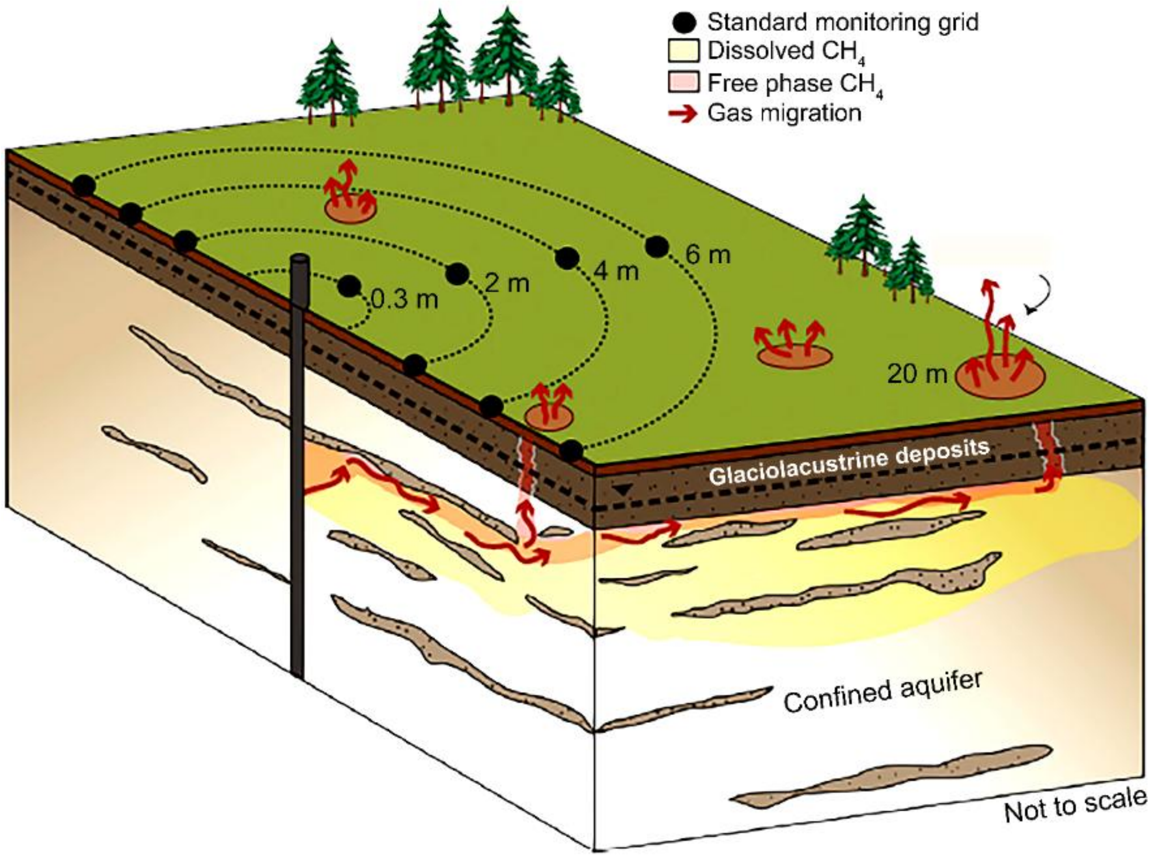


Figure 25 - Schematic illustration of gas migration around a well head in British Columbia (Forde et al., 2019c) indicating preferential pathways leading to gas migration away from the wellbore and constrained by low-permeability shallow layers that make it unpredictable as to gas discharge locations. The authors found that it was equally likely that CH_4 emission would occur > 10 m from the wellhead as < 5 m from the wellhead.

In such cases, because free gas is moving into the soil pores (displacing water), it may be possible to characterize the migration of a gas plume away from the vicinity of a leaking well by electrical-resistivity imaging. Using earlier drilling records and coupled with field mapping, Lagasca and others (2021) traced a 70 m-wide free-gas plume from a well in Utah at a depth of 20 to 55 m bgs.

In Alberta, the regulator has defined an area of the province as the Gas Migration Test Area (AER, 2023). Heavy oil wells (400-700 m depth) in this area appear to be more prone to gas migration problems, leading to a requirement to conduct gas migration testing as part of the well abandonment process. Morais and others (2024) undertook a field study of groundwater contamination immediately surrounding a particular leaky abandoned well that had shown gas migration at ~0.2 m^3/day for more than two decades. The site is shown in Figure 26 with its soil profile and pressure head shown in Figure 27.

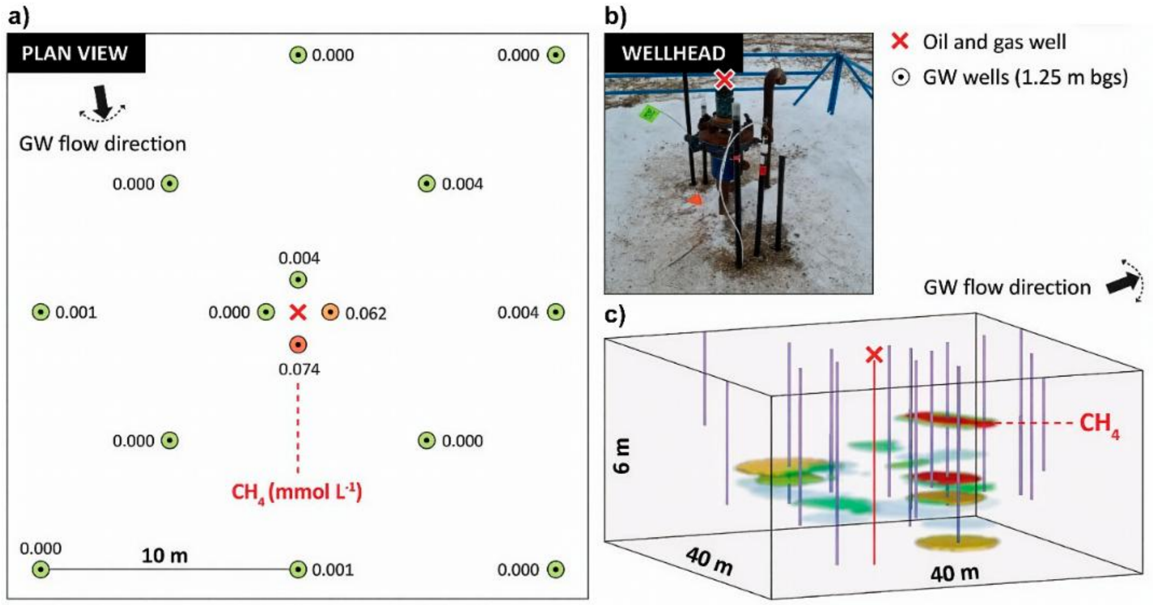


Figure 26 - Abandoned well site in Alberta's Gas Migration Test Area (from Morais et al., 2024).

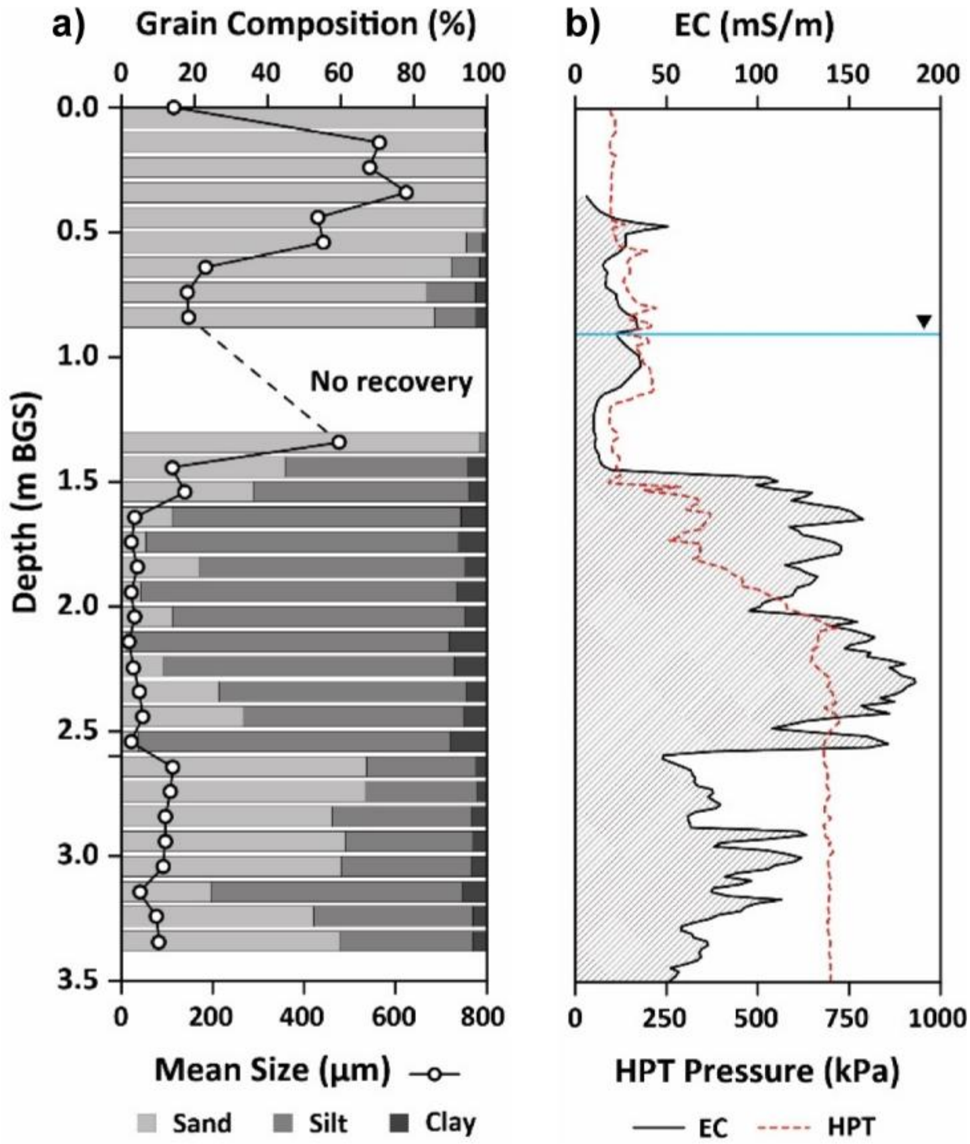


Figure 27 - Vertical soil profile through the abandoned well site, Alberta (adapted from Morais et al., 2024). a)Textural properties of the site. b) electrical conductivity and measured Hydraulic Profile Testing (HPT) pressure. The water table is shown at 0.9 m bgs.

The well site containing the leaky well (marked by an 'x' in Figure 26a) was instrumented with 16 groundwater monitoring wells with 50-cm screens set at 1.25 m bgs and within the saturated zone of the shallow glaciofluvial and eolian aquifer sediments. In addition, soil gas samples were collected from a depth of ~30 cm bgs and recorded concentrations up to 870,000 ppm within 5 cm of the well casing, decreasing rapidly away from the well. Consequently, gas migration was occurring along the wellbore annulus in the absence of emissions from the surface casing vent, which is shown as the inverted pipe next to the well in Figure 26b.

Based on field gas chromatography, the CH_4 zones shown in Figure 26c do not fully saturate the shallow groundwater around the well but are located beneath clay-rich capillary barriers that prevent their buoyant escape. The extent of lateral CH_4 migration was measured up to 10 m from the well. These field studies by Forde, Mayer, and Hunkeler

(2019) in British Columbia and Morais and others (2024) in Alberta raise the question as to the extent of which surface casing vent flow (SCVF) is an indicator of more widespread gas migration from a well and, therefore, of potential groundwater contamination.

Bowman and others (2023) examined this issue by testing SCVF and non-SCVF emissions at 238 plugged (*abandoned*) and unplugged (*suspended*) wells in Alberta and Saskatchewan. The closed-chamber method of measurement employed is shown in Figure 28, in which schematic a) is an example of an abandoned oil and gas well site with a surface casing vent and wellhead infrastructure; schematic b) is a non-surface casing vent chamber measurement configuration; and schematic c) shows a surface casing vent chamber measurement configuration. A surface casing vent is shown in the wellhead photo of Figure 26b.

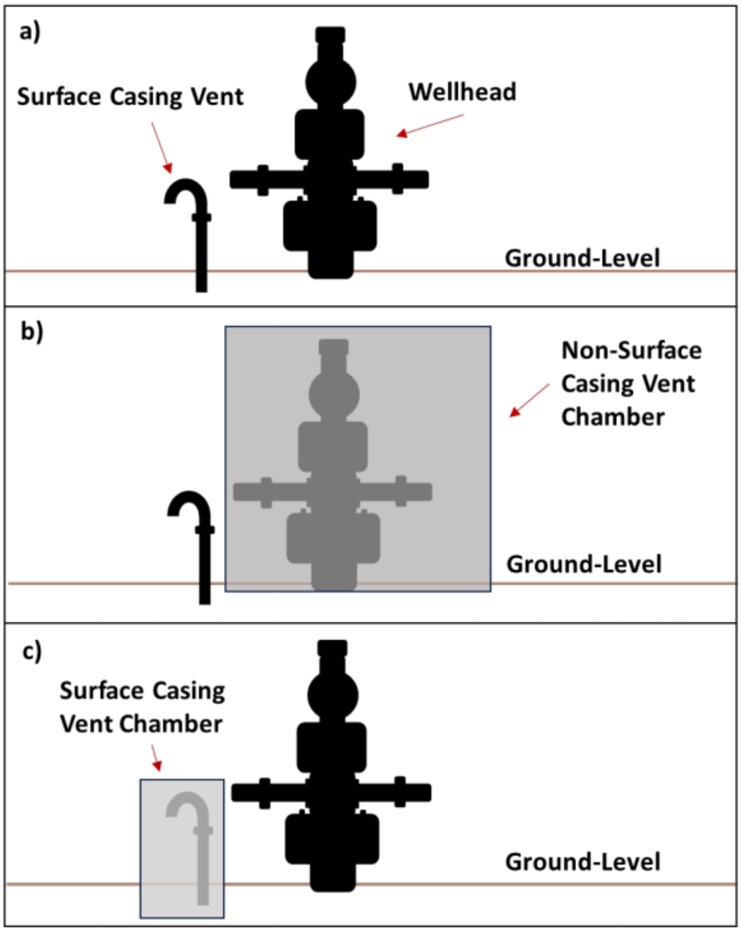


Figure 28 - Measurement of SCVF and non-SCVF at an abandoned well. a) Example of an abandoned oil and gas well site with a surface casing vent and wellhead infrastructure. b) A non-surface casing vent chamber measurement configuration. c) A surface casing vent chamber measurement configuration. (from Bowman and others, 2023).

Generally, Bowman and others (2023) found that plugged wells emitted less than unplugged wells. However, 32% of all abandoned wells—i.e., plugged wells—studied in Alberta exhibited subsurface leakage based on their SCVF emissions. Most importantly, they determined that low non-SCV emissions generally correlate with high SCVF emissions and vice versa. It is reasonable to conclude that this indicates that subsurface leakage is commonly occurring and is leading to gas migration and groundwater contamination.

A detailed forensic analysis of gas migration in British Columbia, Canada has been conducted by Sandl and others (2021) based on the statistical analysis of gas-migration data from British Columbia's public oil and gas well records. They identified intermediate-zone gas-bearing formations as the source of gas migration in northeastern British Columbia and suggested that this might explain the observed spatial clustering of gas wells exhibiting fugitive-gas migration measured beyond the well casings. Completions in these British Columbia wells include full cementation of the surface- and intermediate-casings down to 1500 m depth as shown in Figure 29.

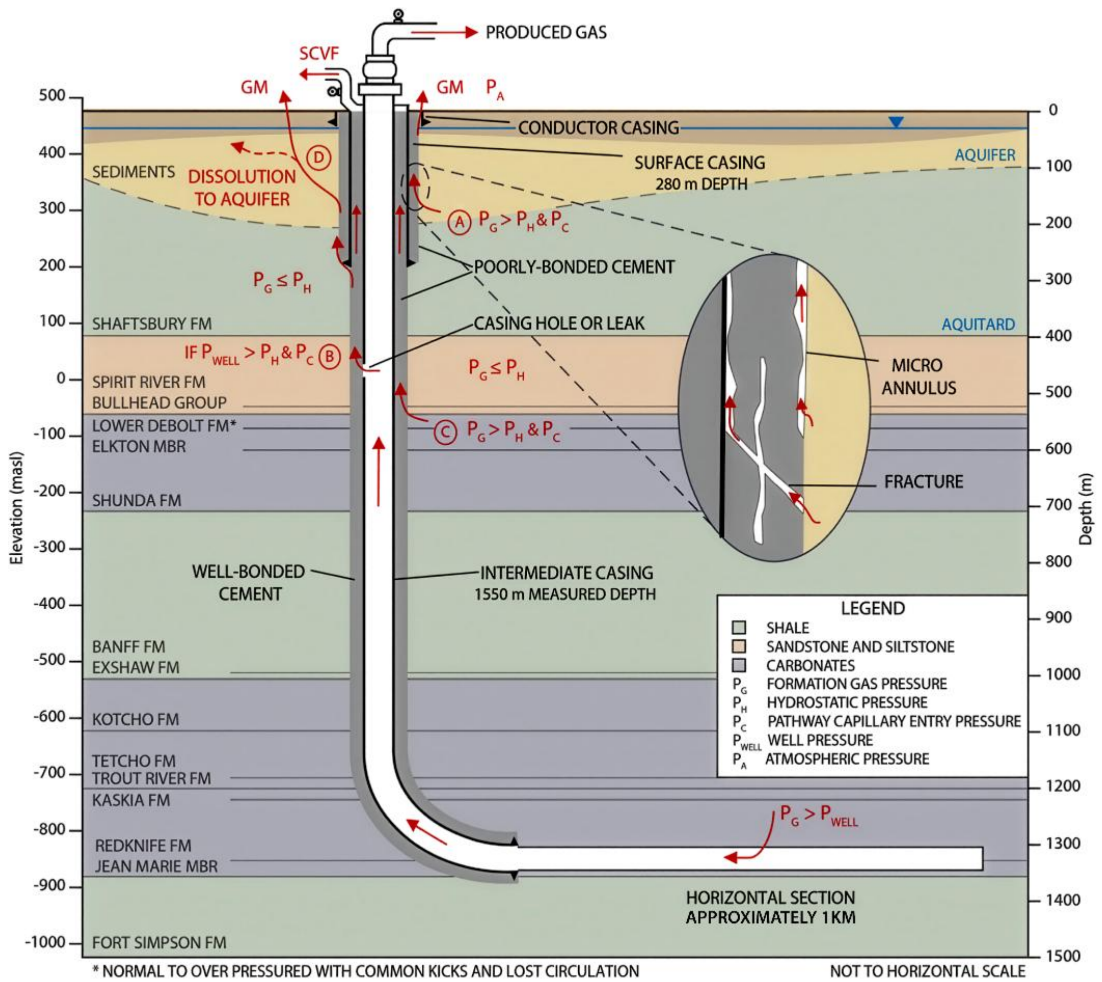


Figure 29 - Stratigraphy and well construction in NE British Columbia, Canada showing potential mechanisms of gas migration and/or SCVF. Completions in these wells include full cementation of the surface- and intermediate-casings down to 1500 m depth. Circles denote modes of failed well bore integrity, with the required pressure condition given as P with a subscript noting the source. (A) shows fractures and microannuli in the cemented annulus between rock and surface casing can allow gas migration to the shallow aquifer. (B) shows the outer annulus of the intermediate casing is charged with produced gas by a casing leak that may be due to a rupture or a leaky casing collar. (C) is the common case of gas migration caused by seepage from an intermediate zone leading to gas migration along the annulus between the intermediate casing and the rock wall of the borehole. (D) show gas in the annulus of the well seeps into the shallow aquifer or discharges to the atmosphere (from Sandl et al., 2021).

Sandl and others (2021) concluded that the coupling of SCVF and gas migration was likely due to poor cement quality, which might include cementing practices that failed to displace drilling mud (Figure 4) or cement type selection that was not optimal for the geologic environment.

Figure 29 illustrates three modes of failed wellbore integrity allowing gas migration. Mode A shows how fractures and microannuli in the cemented annulus between rock and surface casing can allow gas migration to the shallow aquifer. In mode B, the outer annulus of the intermediate casing is charged with produced gas by a casing leak that may be due to a rupture or a leaky casing collar. The common case of gas migration caused by seepage from an intermediate zone, mode C, is shown leading to gas migration along the annulus between the intermediate casing and the rock wall of the borehole. Finally, in mode D, the gas in the annulus of the well seeps into the shallow aquifer or discharges to the atmosphere. Each case provides the required pressure condition given as P with a subscript noting the source.

Furthermore, Sandl and others (2021) found no evidence of gas migration being caused by hydraulic fracturing in their survey of the British Columbia oil and gas well database. They did however note that, in addition to the correlation between recorded SCVF and gas migration, other positive correlations existed between gas migration and (i) the past occurrence of remedial operations, such as cement squeezes or remedial casing, and (ii) blowouts of wells due to encountering highly pressurized formations.

4.1.4 In-Situ Methane Biodegradation

The hydrochemical consequences of the contamination of fresh groundwater by natural gas has been understood since Kelly and others (1985) described conditions in groundwater near a well blowout in Ohio. They reported that the natural oxidants (e.g., O_2, NO_3, SO_4) in the shallow groundwater disappeared with the onset of natural-gas contamination and were replaced by dissolved iron and manganese. Furthermore, the total dissolved solids (TDS) increased in concentration and sulfate reduction of the methane produced hydrogen sulfide. The study by Chafin (1994) in the San Juan Basin in New Mexico and Colorado also indicated a strong association between methane and hydrogen sulfide.

Stumm and Morgan (1981)—and other editions thereof—identified a sequence of reduction-oxidation (redox) reactions in which the natural oxidants (e.g., O_2, NO_3, $Mn\ (IV), Fe\ (III), SO_4$) in the aquifer were reduced by excess reduced carbon in the form of CH_2O, which serves as a stoichiometric proxy for all dissolved organic carbon (e.g., CH_4) in the conceptual redox model they presented. The reduced carbon was oxidized by these naturally occurring oxidants causing the dissolution of iron (Fe (III)) and manganese (Mn (IV)) oxides present in the aquifer. This sequence, based on chemical thermodynamics, provides the theoretical basis for interpretation of these geochemical processes in a "closed system"—i.e., closed to input of oxidants.

The association of hydrogen sulfide with methane contamination of groundwater was substantiated by Van Stempvoort and others (2005) at Lindbergh, Alberta. They showed by isotopic characterization that in-situ microbially mediated methane oxidation was associated with sulphate reduction in groundwater adjacent to the leaky oil well. The greatest distance of gas migration from the leaky gas well through the confined aquifer was ~50 m. The confined aquifer at Lindbergh—glacial outwash sand into which the gas leaked, which was overlain by clay till—may also have allowed the development of a temporary gas cap at the till/sand interface that would have sustained anaerobic conditions.

Such gas entrapment would not occur in an identical unconfined aquifer. Numerical simulation of the Lindbergh migration pattern within an identical unconfined aquifer was undertaken by Roy and others (2016). They concluded that the open redox system of unconfined aquifers would make plume lengths shorter than for a similar confined aquifer because of the higher oxidant recharge, in particular O_2 and SO_4, permitted by the absence of the confining layer

Van Stempvoort and others (2007) subsequently showed that injected groundwater containing 2000 mg/L sulfate and a bromide tracer biodegraded a gas condensate contaminant plume. Therefore, sulfate-amended groundwater injections may provide a low-expense bioremediation method for hydrocarbon treatment in even low temperature (6 to 9°C) groundwater in Alberta, Canada.

In a further study of the Sugar Run case history (discussed in Section 4.1.3), Woda and others (2018) developed a schematic, shown as Figure 30, to illustrate the hydrochemical processes surrounding the leaky gas well(s). Similarly, Schout and others (2018) observed deterioration in Dutch groundwater associated with a gas well blowout that continues to leak methane, which undergoes oxidation by iron and manganese oxide reduction coupled with some sulfate reduction. These reactions clearly follow the closed redox system model of Stumm and Morgan (1981) and indicate the dependence of methane attenuation on the presence and longevity of iron and manganese oxides and dissolved sulfate.

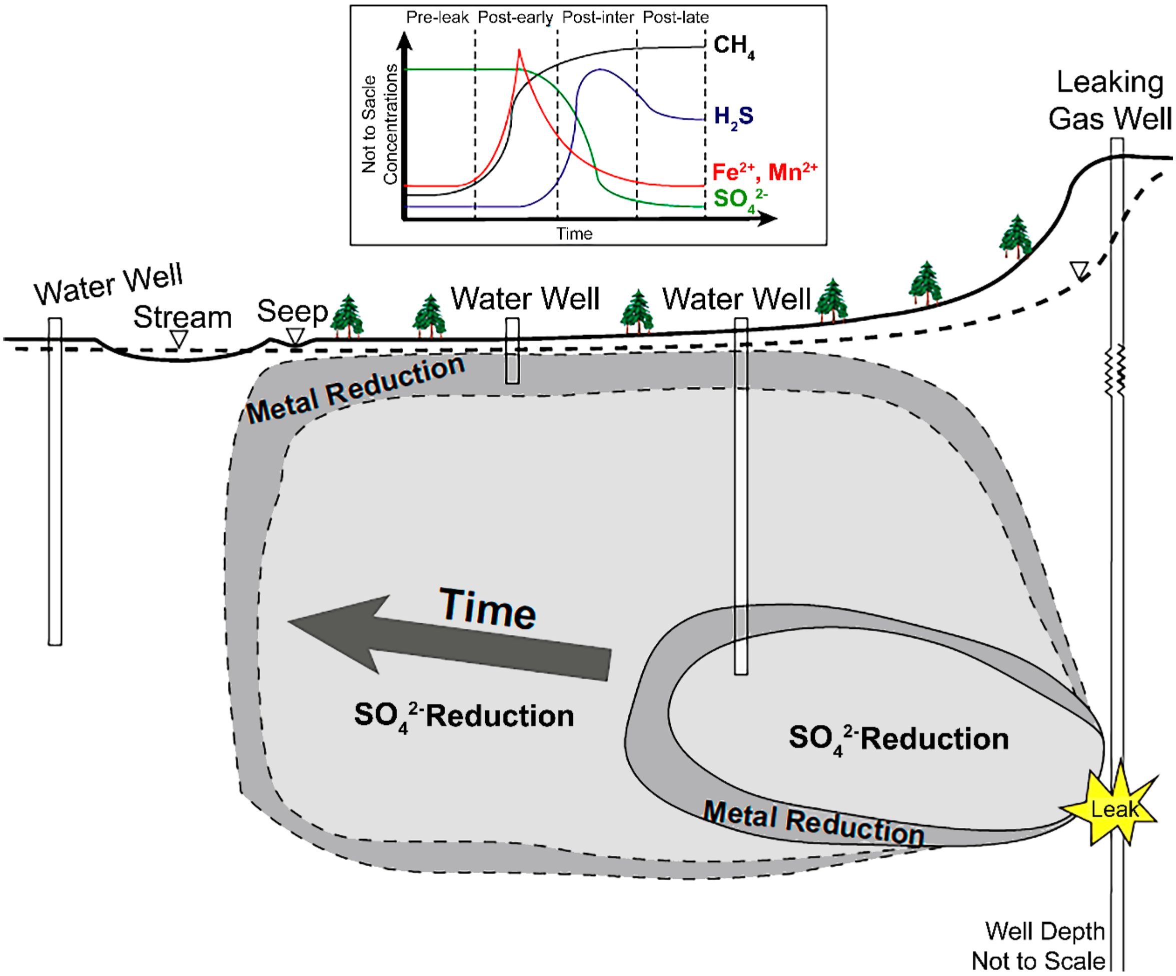


Figure 30 - Schematic of the evolution of groundwater quality as transformed by methane leaking from a casing. The inset graph shows the time series of reactions: Fe_2^+ and Mn_2^+ increase as dissolved oxygen and/or nitrate is reduced by CH_4, then Fe_2^+ and Mn_2^+ decrease as sulfate reduction produces aqueous sulfide that reacts with the dissolved metals to precipitate ferrous sulfide minerals. In this manner, more toxic gas, H_2S, begins to replace CH_4 in the contaminated aquifer (from Woda et al., 2018).

Similarly, sulfate reduction was a critical feature of the complex interaction of hydrocarbon and arsenic contamination of groundwater in the aquifer above the Poso Creek oilfield in California, USA (McMahon et al., 2024). Arsenic from produced oilfield water had been blended with groundwater for crop irrigation and thus infiltrated into the shallow aquifer. Hydrocarbon gases from incompletely cemented oil wells and seepage through a deep fault connecting the oilfield with the aquifer were induced by irrigation wells to mix with the agricultural infiltration (As, SO_4). Methane and the other hydrocarbon gases reduced the infiltrating sulfate to sulfide causing in-situ arsenopyrite (FeAsS) precipitation. The complex suite of hydrologic mixing and geochemical reaction is shown schematically in Figure 31.

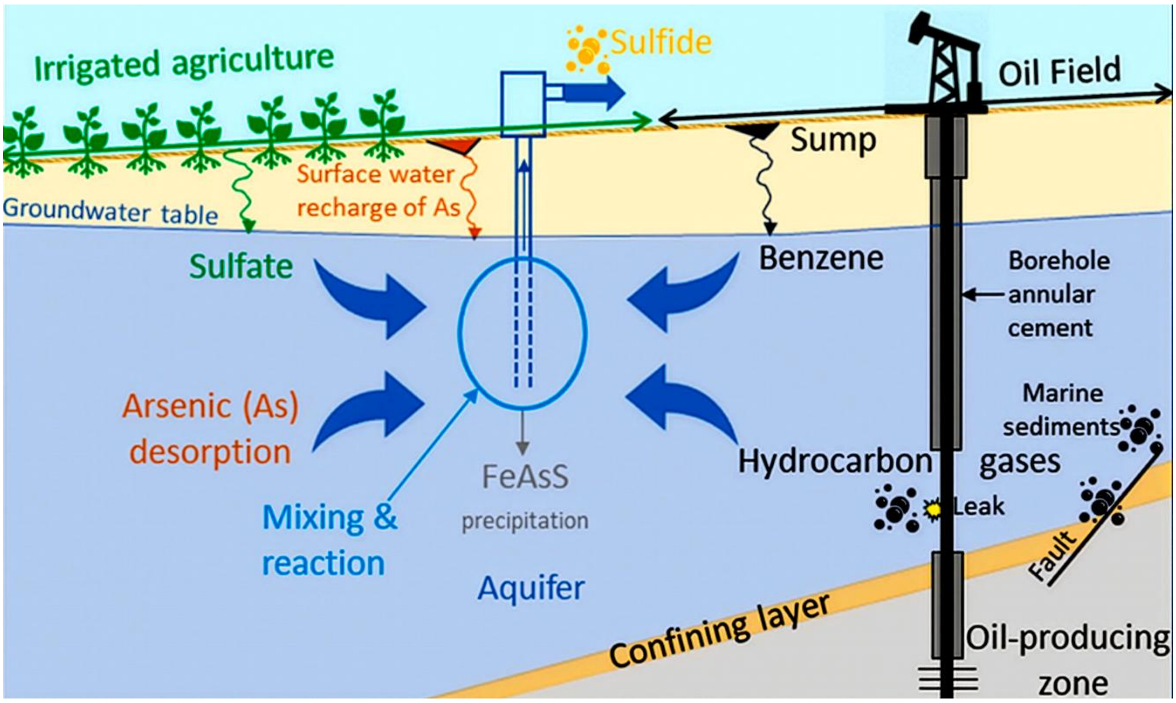


Figure 31 - Schematic of irrigation-induced recharge, leaky oil wells, fluid mixing and geochemical reactions in the shallow aquifer above the Poso Creek Oil Field, California, USA (from McMahon et al., 2024).

Thus, we can expect that natural-gas contamination of freshwater aquifers will result in the oxidized methane being replaced by H_2S, and cause an increase in alkalinity and the concentrations of dissolved iron and manganese. The net effect of these oxidation-reduction reactions will be that groundwater becomes elevated in TDS, thus causing a pronounced deterioration in the quality of the groundwater. These redox processes are not usually considered in numerical simulations, e.g., Moortgat and others (2018) but would limit the spatial extent of gas migration and its duration in-situ. Exercise 4↴ offers an opportunity to consider how to determine if gas leaking from a legacy well is reaching shallow groundwater.

4.2 Surface Emissions

Most of the recent literature on gas emissions from the upstream oil and gas sector represents efforts to improve methane emission inventories and manage (reduce) emissions from oil and gas operations. Therefore, the motivation has largely been to combat climate change, although co-benefits of air quality and groundwater protection are often mentioned.

Methane emissions from upstream oil and gas production can broadly be categorized as “intended” or “unintended” emissions. Intended emissions occur as a part of routine operations and they include gas flaring (Johnson et al., 2017), venting from equipment (e.g., pneumatic controls) (Alvarez et al., 2018; Omara et al., 2018) and production activity (e.g., completion flow back and liquids unloading (Omara et al., 2018)). Unintended emissions, also referred to as fugitive emissions, occur due to equipment malfunctions and other "abnormal processes" (Alvarez et al., 2018), including those related to subsurface gas migration. Surface emissions related to subsurface gas migration are generally viewed as a relatively small component of overall methane emissions from the upstream oil and gas sector. However, blowouts and well failures such as the Aliso Canyon gas leak in California, USA, can be catastrophic (Conley et al., 2016) and result in long-lasting groundwater contamination (Schout et al., 2018).

Here, we consider *surface emissions* that are related to subsurface gas migration, including emissions from soils (Lyman et al., 2017), active wells (Omara et al., 2018; Riddick et al., 2019), abandoned wells (Boothroyd et al., 2016; Kang et al., 2016; Kang et al., 2014; Riddick et al., 2024; Townsend-Small et al., 2016; Williams et al., 2021; Williams et al., 2019), and other oil and gas infrastructure such as pipelines (Boothroyd et al., 2018). Emissions from soils occur because of gas migration through aquifers and unsaturated zones and can occur as gas phase migration or a combination of transport of dissolved gases in water and gas phase transport. The source of the gas in soils may be from subsurface leakage of active and abandoned wells and infrastructure or methanogenic (microbial) activity. It is important to note that in regions of oil and gas development there is a wide range of infrastructure (e.g., pipelines) and facilities (e.g., tanks) that can emit methane and identifying the exact source of leakage can be challenging. This is especially true if the leaking component is buried and not visible at the ground surface.

The first publication of methane emission rates directly from abandoned wells was in 2014 (Kang et al., 2014), which described measurements at 19 abandoned wells in northeastern Pennsylvania, USA. Prior to this time there had been measurements of soil-gas emissions adjacent to active oil and gas wells using flux chambers (Erno and Schmitz, 1996; Junhong et al., 2008; and Sechman et al., 2013). Kang and others (2014), however, sought to directly measure by the flux chamber method both unplugged and plugged wells, which were all referred to as *abandoned*.

The first commercial oil well was drilled in northeastern Pennsylvania, USA, which is home to the Bradford oil field, the most productive oil field in the nineteenth century. In the early twentieth century, oil production began to decline and methods to increase production, known as enhanced oil recovery techniques, in particular water flooding, were widely practiced in the Bradford oil field. The result is a very high density of abandoned wells. There are also numerous gas fields in western Pennsylvania—some in very deep formations—such as the Oriskany sandstone. The first 19 measured wells are a combination of old oil wells—mainly in the Bradford Oil Field—and deep gas wells. This first study showed that methane emissions from abandoned wells may represent 4 to 7% of state-wide anthropogenic methane emissions in Pennsylvania, which warranted further investigation.

Key findings from this seminal 2014 study are as follows.

- Both plugged and unplugged wells emit methane and other gases (including CO_2, ethane, propane, and butane) to the atmosphere.
- Mean methane emission rates from abandoned wells can be substantial at 0.27 kg/d/well. This mean value was dominated by high emitters, which represent three out of the 19 wells with emission rates three orders of magnitude higher than the median emission rate.
- The gas sources for the high methane-emitting wells are likely thermogenic, from deep reservoirs where oil and gas are typically found. Stable carbon isotopes of methane ($\delta^{13}C$-CH_4) and the presence of heavier hydrocarbons (ethane, propane, n-butane) are used to estimate the source of the emissions.

Subsequently, Kang and others (2016) expanded the geographic extent of their measurements in Pennsylvania to 88 wells across western Pennsylvania from which they determined the role of well type and plugging status on identifying high emitters. They found that high emitters are likely to be unplugged gas wells or plugged and vented gas wells. The plugged and vented wells are abandoned wells in coal areas that are plugged but with a vent installed on "top of the inner string of casing;" as delineated in Pennsylvania Code, Title 25: Environmental Protection, Chapter 78, Subchapter D, 78.92 and 78.93 (Department of Environmental Protection, 2018). The primary objective of venting is for coal mine safety. They also found through multiple measurements (up to 10) over three years in various seasons that high emitters are less likely to be influenced by seasonality and appear to continually emit methane at the same order of magnitude.

In addition to the Kang and others (2016) study, the 2014 Pennsylvania study prompted numerous subsequent measurement studies in the USA, Canada, and the United Kingdom (Boothroyd et al., 2016; El Hachem & Kang, 2023; Lebel et al., 2020; Pekney et al., 2018; Riddick et al., 2019; Riddick et al., 2024; Saint-Vincent et al., 2020; Townsend-Small et al., 2016; Townsend-Small & Hoschouer, 2021; Williams et al., 2021; Williams et al., 2019). The El Hachem & Kang (2023) review is particularly thorough and documents methane leakage from oil and gas wells caused by a wide variety of factors.

The 2014 and subsequent studies also prompted the US Environmental Protection Agency (USEPA), Environment and Climate Change Canada, and the Intergovernmental Panel on Climate Change to include abandoned wells as a new category in national greenhouse gas inventories. After several rounds of memoranda, reports, and public commenting, methane emissions from abandoned oil and gas wells were included in the USA greenhouse gas inventory (GHGI) and the Canadian National Inventory Report (NIR) in 2019. At the same time, the abandoned oil and gas wells were included in the 2019 Refinement to the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC, 2019).

It is clear that methane emissions from abandoned or non-producing oil and gas wells are underestimated in greenhouse gas inventories. Based on 598 direct measurements in Canada and the US,A which is very small relative to the number of abandoned wells, Williams and others (2021) found that annual methane emissions in such wells across the USA were underestimated by 20%. In Canada emissions are estimated to be 150 to 170 percent higher than reported in the federal inventory. Boutot and others (2022) estimated that the methane emissions from 123,318 documented orphaned wells were 5 to 6% of total methane emissions from all abandoned wells in the USA. However, there may be up to a million undocumented orphaned wells in the USA alone and the associated emissions are not included in the greenhouse gas inventories.

There remains the likelihood that many "super-emitters" have not been detected and measured. Using dynamic chamber measurement, Riddick and others (2024) recently measured an abandoned Colorado, USA, well emitting 76 kg CH_4/hr, which currently is the highest emission measured from a single well. In addition, aerial measurements in British Columbia, Canada indicate that there may be many unmeasured/undetected high-emitting non-producing wells (Pozzobon et al., 2023). In Alberta, Canada, Bowman and others (2023) found that 32% of abandoned wells had subsurface gas leakage on the basis of their SCVF measurements rather than using data compiled by the provincial regulator. Consequently, the Alberta government's well integrity data was missing 68% of leakage occurrences. Bowman and others (2023) concluded that in Canada SCVF emissions dominate methane emissions at abandoned oil and gas wells and that this indicated subsurface leaks are substantial and groundwater may be threatened.

5 Experimental Studies

In their review of the evolving shale-gas controversy, Jackson and others (2013) stressed the need for "field testing of potential mechanisms and pathways by which hydrocarbon gases, reservoir fluids, and fracturing chemicals might potentially invade and contaminate useable groundwater" (p. 488). Since that time, there have been at least three important field experiments that address this need and complement the use of the forensic evidence summarized in Section 4. In addition to these field studies have been sand-tank experiments in which physical conditions can be controlled to examine geological and other features influencing contaminant transport.

The studies reported here in Section 5 are included because they were conducted under controlled conditions. Many studies have been reported that were conducted to examine contamination after the event; the best substantiated of those forensic studies were reported in Section 4.

5.1 Laboratory experiments

Van De Ven and Mumford (2019; 2020a; 2020b) have investigated the dynamics of gas migration and capillary retention in homogenous porous media with water-saturated, sand-tank experiments. Initial scoping studies used the ratio of dimensionless numbers—the Bond and Capillary numbers—to understand the dynamics of gas flow (Van De Ven & Mumford, 2019) in terms of the ratio of gravity to viscous forces. This is similar to the approach used by Morrow (1979) with oil ganglia and Jin and others (2007) with dense non-aqueous phase liquids solubilized by surfactants. These interpretations allowed the identification of zones of continuous, transitional, and discontinuous gas flow without interfacial tension being a factor because it cancels out in the ratio of Bond to Capillary numbers. They showed that continuous gas flow regimes occur at low values of Bond to Capillary number ratios, where viscous forces predominate, while discontinuous flow occurs at high ratio values, where gravitational forces—i.e., gas buoyancy—predominate. This is consistent with our previous discussion with respect to the capillary entry pressure.

Subsequently, Van De Ven and Mumford (2020a) used two-dimensional flow tanks (150x150x2 cm) to investigate migration of fugitive gas in homogeneous and heterogeneous sand. Figure 32 illustrates how a medium-grained sand lens can act as a capillary barrier to gas flow and disrupt an otherwise simple profile of aqueous gas concentration.

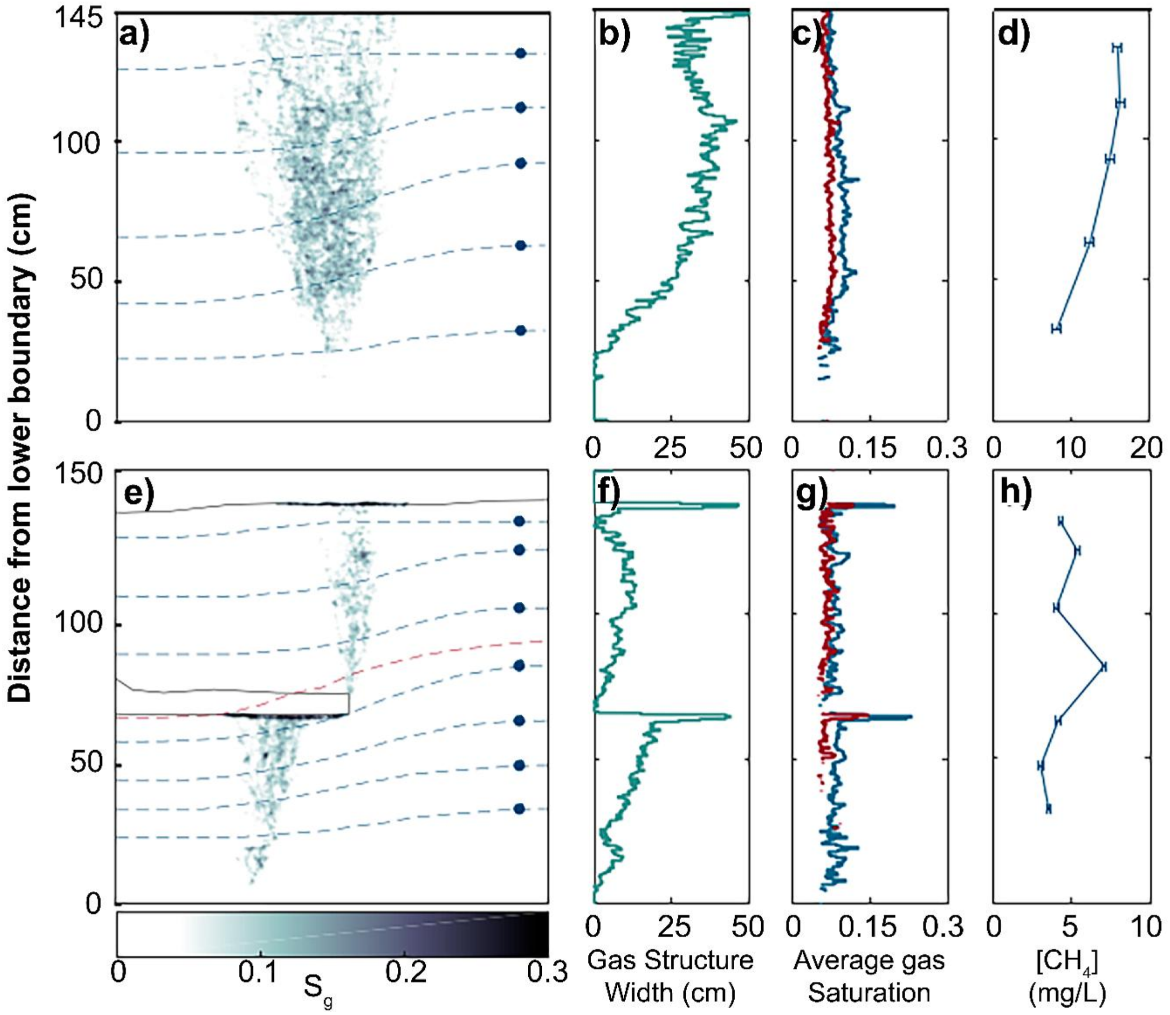


Figure 32 - Experiments with sand tanks (150x150x2cm) with groundwater flow from left to right and fugitive gas introduced at the base about 50 cm from the left side of the tank. The dashed lines indicate flow paths across the tank for the homogeneous (a) and heterogeneous (e) experiments. For the heterogenous experiment (e), a medium-grained sand lens, which does not extend the length of the tank, is positioned within the coarse sand at 70 cm elevation as shown in (e). It acts as a capillary barrier to gas flow. Panels (a) and (e) show the steady-state gas concentration with a color legend included below (e). These panels include blue dots indicating depths where water samples were collected. Additional panels show conditions at steady state as a function of depth for the homogeneous and heterogeneous (a, e) experiments, respectively: (b, f) width of the gas zone, (c, g) average gas saturation, and (d, h) aqueous methane concentration (modified from Van De Ven & Mumford, 2020a).

In a second paper, Van De Ven and Mumford (2020b) examined gas release occurring within the homogeneous sand tank to the atmosphere, i.e., the case of an unconfined aquifer. They determined that the experiment shown in Figure 33 resulted in most of the methane being released to the atmosphere (61 to 65%) with much less dissolving into the groundwater that the gas flowed through to reach the surface (35 to 39%).

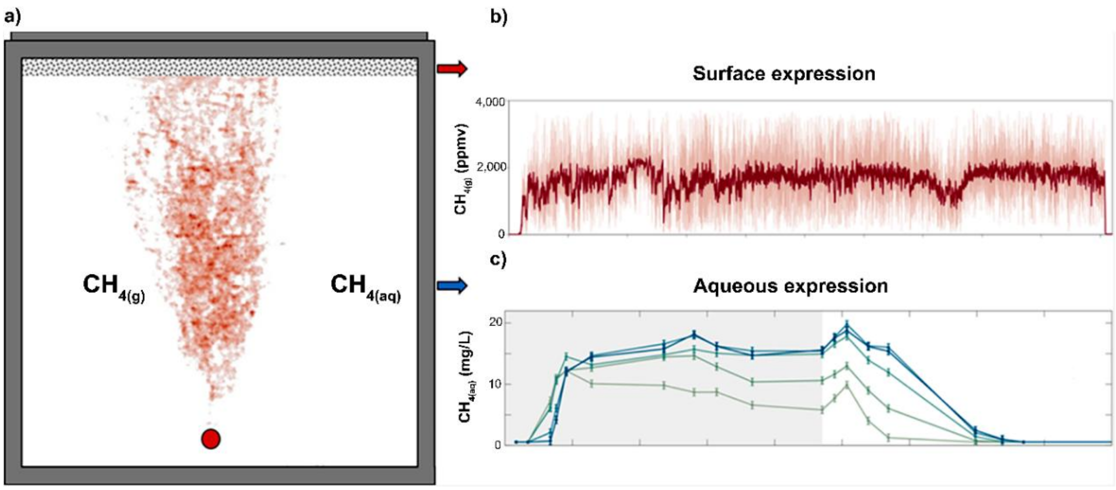


Figure 33 - (a) Schematic of gas release from a point source (red dot) in a sand tank (150x150x2 cm with a confining lid) filled with homogeneous coarse sand overlain by unsaturated glass beads across which gas flow is captured and measured. (b) Range of gas release to the atmosphere throughout the experiment in ppmv of methane. (c) Aqueous methane in mg/L at five equally spaced sample depths with the lightest color at 25 cm above the injection point and the darkest color 125 cm above (adopted from Van De Ven & Mumford, 2020b).

5.2 US DOE Greene County Study

A field experiment operated by the US Department of Energy within the Marcellus Shale gas play involved hydraulic fracturing of six horizontal Marcellus Shale wells (Hammack et al., 2014; Sharma et al., 2015). Monitoring occurred in shallower gas wells, which had been previously completed in the Upper Devonian 1200 m above the Marcellus and 1000 m below ground surface. Figure 34 illustrates the disposition of two monitoring wells (UD-2 and UD-5) relative to a Marcellus Shale horizontal well.

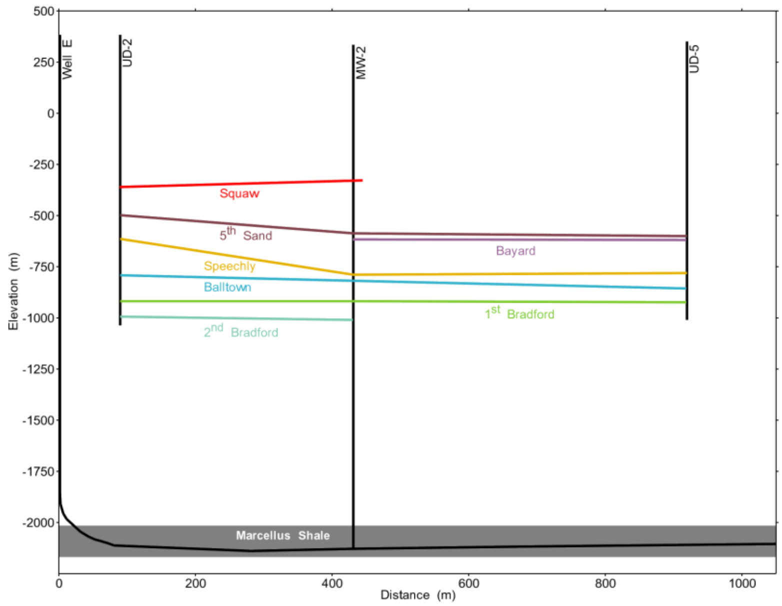


Figure 34 - Greene County, Pennsylvania, field experiment. Schematic cross section along horizontal Marcellus Shale Well showing vertical Marcellus Shale gas well (MW-2) and two Upper Devonian/Lower Mississippian gas wells (UD-2 and UD-5) that were completed in multiple zones and monitored for pressure as well as chemical and isotopic gas contents during a 14-month period following fracking in the Marcellus Shale. No evidence of gas or brine migration from the Marcellus Shale was observed after 14 months (adapted from Hammack et al., 2014).

No isotopic or molecular evidence of the Marcellus gas was detected in any of the seven shallow monitoring wells after 14 months of monitoring, nor was there any increase in gas production from the shallow gas wells that would have indicated a connection with the Marcellus. Furthermore, none of the perfluorocarbon tracer injected with the fracking fluid was recovered from the Upper Devonian gas wells shown in Figure 34. Finally, microseismic monitoring indicated that the fractures induced around the Marcellus Shale horizontal wells never rose higher than 1,500 m below the base of potable groundwater aquifers. The maximum "rise" was deemed to be the uppermost recorded microseismic event exceeding a selected magnitude threshold. This induced microseismicity is expected to occur well in advance of the physical arrival of fracturing fluids, i.e., the microseismicity front travels further than the fracturing fluids.

Overall, these results indicate that transmissive vertical faults and fractures were absent at this test site chosen by the US Department of Energy to investigate the presence of such discontinuities above the Marcellus Shale. The fault noted by Llewellyn and others 2015, located 500 km away in Bradford County, Pennsylvania, dips only 16^{0} from the horizontal, so this fault would not be a deep pathway to the Marcellus Shale either.

5.3 Borden Experiment

In July 2015, the Borden field site in Ontario, Canada, was host to an experimental release of methane within the water saturated zone of a horizontally-bedded granular-sand aquifer (Cahill et al., 2017) that had been the site of many previous field experiments dating back to the 1980s. Figure 35 illustrates the experimental field installation.

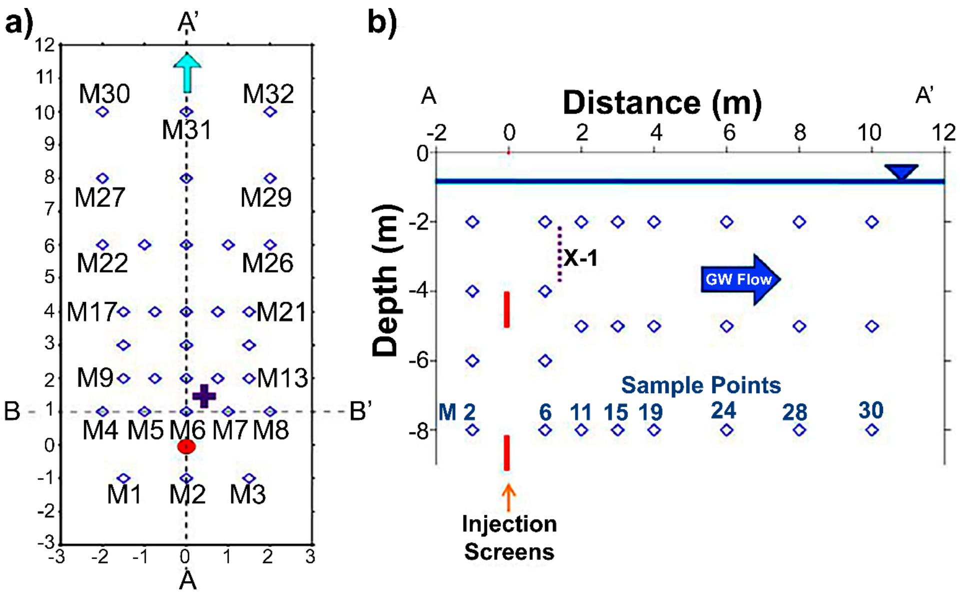


Figure 35 - a) Plan view of multi-level groundwater monitoring network instrumentation at the Borden, Ontario, Canada field site illustrating multi-level sample-well locations (blue diamonds) numbered M1 to M32 starting at coordinates −1, −1.5 from left to right moving away from the injection (red dot) and the high-resolution multi-level monitoring well indicated by a purple cross in (a) and X-1 in (b). Distances are in meters. (b) Cross section along experimental centerline (A—A') showing depth discrete, multi-level groundwater sampling-point positions relative to the gas injection screens (from Steelman et al., 2017).

During the *active leakage* stage of methane release into the two injection wells shown in Figure 35, fugitive gas migrated rapidly in the sand aquifer. The methane traveled substantial lateral distances, creating both extensive free-phase and dissolved-phase methane plumes. The dissolved methane plumes migrated much faster than advective groundwater flow rates. This was the case even when low release rates were occurring—rates comparable to reported flows from casing vents in Alberta and British Columbia.

The results suggest that methane was migrating as a free-phase gas and subsequently dissolving (Cahill et al., 2018). The gas migration pathway was controlled by geologic heterogeneities within the Borden aquifer, specifically the anisotropic structure of the sandy sediments. As with other multiphase-flow studies in granular sediments, the horizontal layering of the aquifer, which is a common feature of sedimentary aquifers, results in permeability and capillarity contrasts that direct, trap, or divert gas laterally. Gas buoyancy causes a continuous propensity for upward migration when there are permeable windows through confining aquitards and capillary barriers. This finding strongly points to the advantage of employing multilevel monitoring wells to evaluate gas migration.

The experiment included geophysical monitoring of the gas migration using ground penetrating radar (GPR) and electrical resistivity tomography in a time-lapse sequence (Steelman et al., 2017). These tools showed clear evidence of episodic gas migration events indicating that gas pressure built up until it exceeded local entry pressures, followed by gas migration events over distances up to 17 m. The gas preferentially migrated through high-permeability sediments, with a portion eventually reaching the vadose zone.

The aerobic biodegradation of the released hydrocarbon gas was investigated in the one-meter-thick vadose zone at the experimental site (Forde et al., 2018). It indicated that ~30% of the injected gas was released to the atmosphere. The surficial CH_4 and CO_2 (i.e., oxidized CH_4) gas releases were strongly influenced by the rate of gas release into the aquifer and by the heterogeneous aquifer permeability. The gas emissions exhibited strong spatial and temporal variation. Locally, areas with subsurface CH_4 concentrations that exceeded the lower explosive limit (5% v/v) for CH_4 were observed. In some cases, CH_4 concentration reached 90% (v/v) very near the ground surface. Aerobic biodegradation in the vadose zone was the only bioremediation process active in reducing dissolved CH_4 concentrations as reported by Forde, Cahill, Mayer and others (2019) for a period of 700 days after CH_4 injection. They reported that limited oxidation of CH_4 occurred through nitrate and sulfate reduction and the reductive dissolution of ferric oxides.

5.4 UBC Measurement of Gas Leakage and Migration at a Well Pad

The soil-gas flux of CH_4 was further investigated in British Columbia, Canada by Forde, Cahill, Beckie, and Mayer (2019) using techniques similar to those employed at Borden including efflux chambers and stable carbon isotopes but within a deep vadose zone (>60 m) at wells in the Montney play of northeastern British Columbia. They reported that the CH_4 and CO_2 effluxes were significantly affected by the barometric pressure and noted that during periods of increasing barometric pressure, CH_4 effluxes declined. However, whenever barometric pressure decreased, the CH_4 effluxes rapidly increased. This increase could be of the order of >20-fold in less than 24 hours.

Figure 36a shows the soil-methane efflux measured from a long-term chamber – LT-Ch* for an experiment illustrated in Figure 36b. The chamber is at the surface, two meters down gradient of the 12-meter-deep injection well. The methane effluxes vary with the barometric pressure during the 25 days of record. The monitoring grid is shown in Figure 36b with as many as 123 grid locations monitored for 13 sampling events using closed chambers fitted with an infra-red gas analyzer coupled with a greenhouse gas analyzer. Figure 36b illustrates the barometric effects on effluxes on day 4 with low barometric pressure and day 6 with high barometric pressure.

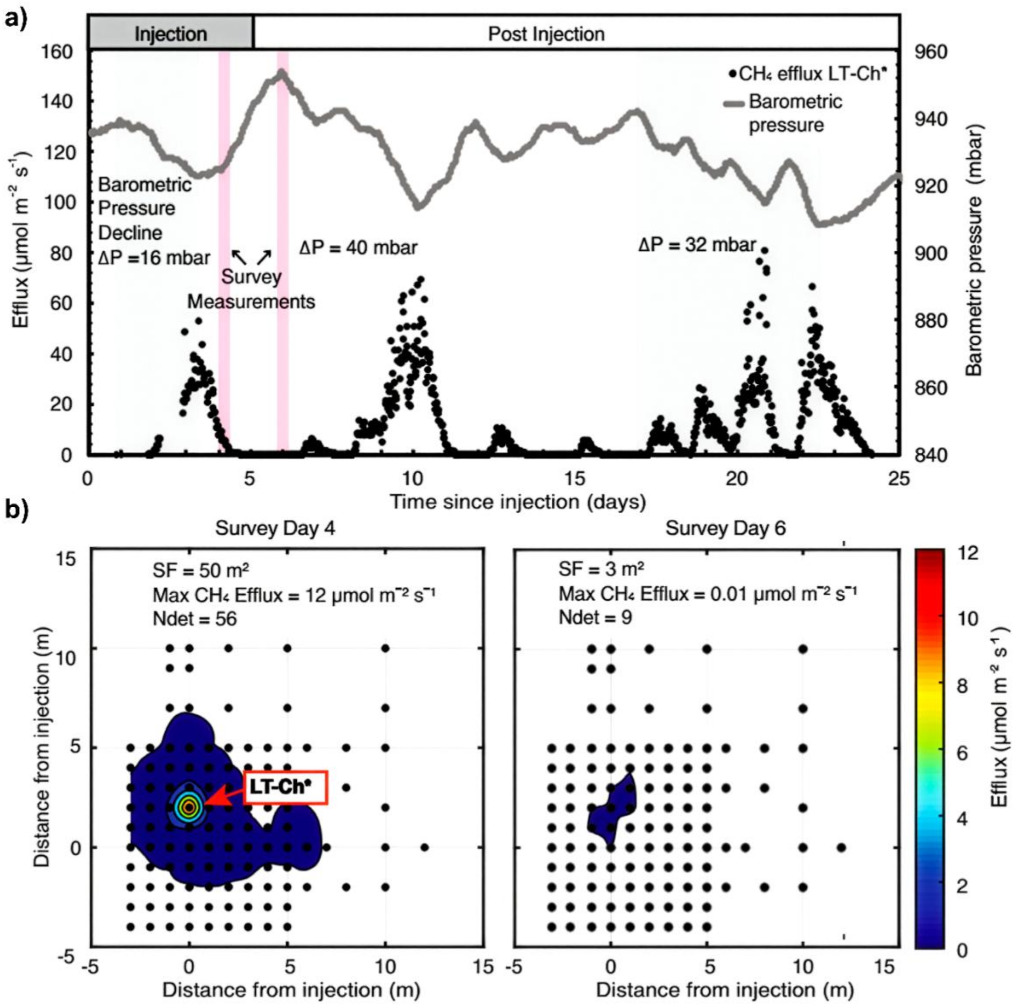


Figure 36 - Results from the British Columbia vadose zone gas migration experiment (Forde, Cahill, Beckie, & Mayer, 2019).a) Injection and monitoring periods showing barometric pressure and CH_4 efflux at the surface. b) Efflux distribution on day 4 with low barometric pressure and day 6 with high barometric pressure – the dates are indicated as pink bars in (a). SF = surficial efflux footprint. N_{det} = number of locations with detectable CH_4 emissions.

In short, at sites like this one in British Columbia with a thick vadose zone (>60 m), barometric-pressure fluctuations can affect gas transport from the ground surface. Forde and others (2018) further noted that the variable spatial and temporal gas releases (effluxes) pointed to the need to monitor gas migration spatiotemporally rather than a one-time visit as is current practice. These results also emphasize the several variables affecting the migration and flux of CH_4 in the shallow vadose zone. The penetration of the vadose zone by a gas slug from a leaky well can occur when gas pressure exceeds the sum of capillary entry and pore pressure. Migration of gas through the vadose zone will depend on the relative permeability and capillarity along the flow path. If the gas pressure is sufficient to overcome all capillary resistance along the flow path, its release at ground surface may still be influenced by the barometric pressure, as would be expected based on Darcy’s law.

6 Sampling and Monitoring

6.1 Groundwater

As soon as hydraulic fracturing became a standard stimulation technique in the natural gas (shale gas) industry, it became apparent that protocols were needed to define how to collect reliable groundwater quality (GWQ) samples from monitoring or other types of wells. This need was identified as the natural-gas industry realized that it had to demonstrate that fracking and well-pad operations were not causing perceived GWQ concerns in nearby domestic and farm water wells for residents and regulators.

Rivard and others (2018b) discuss sample collection in monitoring wells that are usually drilled for observing general GWQ properties, but which are ideal for monitoring natural gaseous hydrocarbons—methane (C_1), ethane (C_2), propane (C_3) and butane (C_4) (this is also discussed by Roy & Ryan, 2010). Molofsky and others (2016, 2018) discuss methods to optimize collection of samples specifically for fugitive natural gas when only domestic and farm wells—*landowner wells*—are available for sample collection. McMahon and others (2019) have drawn attention to the need to measure groundwater-age indicators—tritium, sulfur hexafluoride, or radiocarbon—in shallow aquifers so that groundwater-monitoring programs in areas of natural gas development consider the rate of groundwater flow through flow systems containing natural gas wells.

In this section, we first consider the constraints of collecting and analyzing reliable GWQ samples and especially obtaining reliable methane concentrations. This is of significant importance in that methane is a potential asphyxiant and the cause of explosions—such as shown in Figure 19—when confined spaces are filled by gaseous methane and oxygen (air). We then consider *baseline GWQ monitoring* programs that use various types of water wells in the collection of GWQ data—known as *pre-drill* samples.

6.1.1 Sampling and Analysis for the Presence of Natural Gas

The experience of hydrogeologists and co-workers in refining GWQ sampling techniques dates to the 1960s. These methods are summarized and kept up to date online in the *National Field Manual for the Collection of Water-Quality Data* of the US Geological Survey (https://www.usgs.gov/mission-areas/water-resources/science/national-field-manual-collection-water-quality-data-nfm↗). However, the sampling of dissolved and free-phase gases such as methane is not explicitly covered in this USGS manual. Consequently, various approaches have developed to measure concentrations and fluxes of methane in particular, and natural gas in general.

The difficulty of measuring concentrations of natural gas is summarized in a critical article by Ryan and others (2015). These authors point out the "lack of verified, standard approaches for the combined sampling, storage, manipulation, and analysis of dissolved groundwater gases" (p. 218). The wide range of techniques employed is illustrated in the report of Hirsche and Mayer (2007). Ryan and others (2015) identified (i) how calculations and corrections must be undertaken to estimate dissolved methane concentrations accurately, and (ii) the safeguards that must be taken during sampling, preserving, and analyzing dissolved gases to avoid gas loss.

The gold standard for such measurement is the coupling of a sample analysis for all natural gases (e.g. O_2, N_2, H_2S, CO_2, plus C_1, C_2, C_3, C_4) with measurement of the total dissolved gas pressure (TDGP) in-situ—i.e., within the sampled well (Roy & Ryan, 2010, 2013). By installing a TDGP probe in a monitoring well that is sealed in place with an inflatable packer, these authors showed that when the pump is turned on to induce fresh groundwater to enter the well, the TDGP drops and dissolved gas—in this case, dissolved oxygen (DO)—degasses from the groundwater in the packed-off section. This degassing or exsolution is known as *ebullition* and results in a free-phase gas and a reduced dissolved gas concentration. Figure 37 shows the sampling apparatus and Figure 38 shows field results as pumping progresses in-situ. As Ryan and others (2015, p.221) observe, "one needs to report dissolved gas concentrations as 'estimates' unless either i) the total mass of gas molecules are fully captured and preserved (i.e., under in situ water pressure) and included in the analytical approach, or ii) in situ total dissolved gas pressure is measured and combined with robust gas composition analysis."

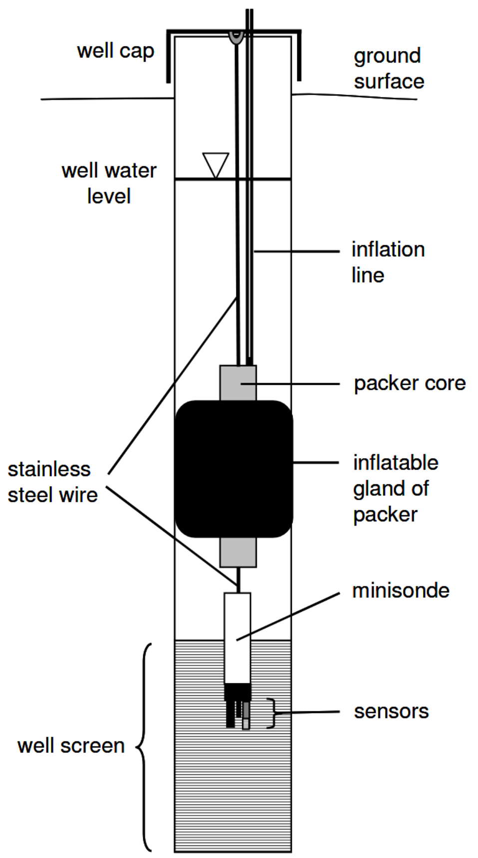


Figure 37 - Total Dissolved Gas Pressure (TDGP) measurement in a monitoring well in Alberta, Canada showing the packer and sensor placed in a monitoring well.

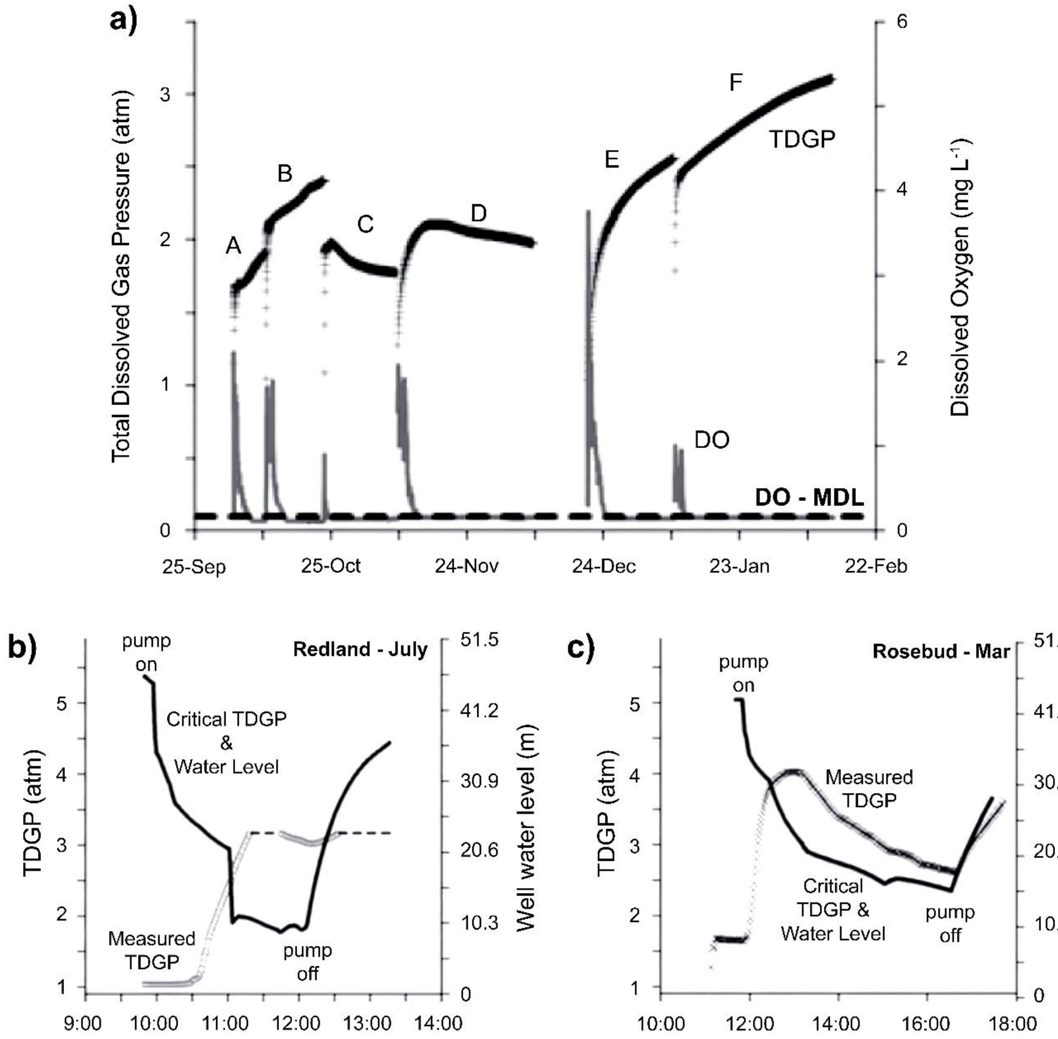


Figure 38 - In-well degassing reflected by TDGP measurements in Alberta, Canada, and by the presence of dissolved oxygen that disappears with the inflation of the packers. a) Rosebud monitoring well: TDGP is shown by symbols and dissolved oxygen (DO) is shown by the gray line. No pumping is occurring. MDL is the minimum detection limit (dashed horizontal line) for the dissolved oxygen sensor (labeled DO - MDL). Deployment periods are indicated by letters: A Packer installed and inflated, B Packer inflated, C packer removed, D packer installed and deflated on the second day, E packer inflated, and F packer inflated. b) and c) Measurements in the Rosebud and Redland wells: measured TDGP (symbols), water level above the sensors (line), and calculated critical TDGP (water pressure + atmospheric pressure). Dashed lines indicate that the limit for the TDGP sensor was reached. First the packers are inflated to control gas transfer in the well and then the pump is turned on to induce fresh groundwater flow into the well. TDGP, DO, and head are monitored during pumping (from Roy & Ryan, 2010). DO degassing occurs immediately with initiation of pumping. TDGP increases as fresh groundwater enters the screened interval of the monitoring well but DO decreases to a concentration below the MDL. The local barometric pressure is about 0.91 atm which is ~92 kPa (modified from Roy & Ryan, 2010).

Roy and others (2022) illustrate the use of TDGP probes in three monitoring wells situated above the Utica Shale in Québec, Canada. The results indicate that the TDGP-derived methane concentrations were on the order of 34 to 156 mg/L. These were 3 to 12 times higher and rather more stable than concentrations determined by conventional methods, which have maxima of ~30 mg/L in fresh water at 101 kPa.

It is widely perceived by industry and consultants that in-situ monitoring of the kind espoused by Ryan and others (2015) is impractical for reasons of cost, liability, and accessibility (Molofsky et al., 2016) and the absence of monitoring wells in some areas is of concern. Consequently, it has been standard practice to use sampling techniques that have evolved using the techniques of Gorody (2007, 2012). These attempt to minimize gas losses in the field and use of domestic and/or farm wells to obtain sufficient spatial discrimination of the distribution of dissolved gases near energy well operations. Some states in the USA often provide specific guidance to be followed in sample collection and analysis, e.g., *predrill* sampling guidance such as Pennsylvania's Department of Environmental Protection (2018) "Recommended Basic Oil and Gas Pre-Drill Parameters" fact sheet.

Recommended sample collection methods are reviewed and assessed by Molofsky and others (2016) and are shown in Figure 39. At methane concentrations below 20 mg/L, the three methods shown in Figure 39 provide similar measurements. The two methods illustrated using volatile organic analysis (VOA) vials have the disadvantage of not providing a closed-system sample, while the IsoFlask® eliminates losses due to exposure from de-gassing. However, as Ryan and others (2015) have shown, substantial degassing—i.e., *exsolution*—of dissolved gas may occur within water wells, consequently the sample may already have lost much of the target analytes—i.e., methane (C_1), ethane (C_2), propane (C_3) and butane (C_4) gases.

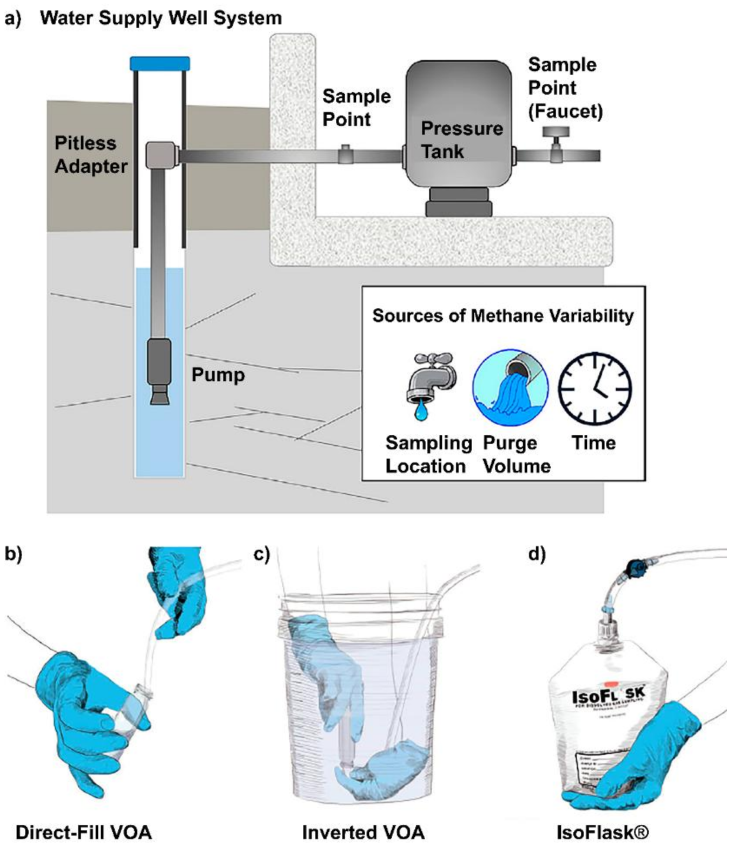


Figure 39 - Gas sample collection methods. a): Schematic of a typical domestic or farm well used for collection of groundwater samples in water wells potentially affected by fugitive gas indicating that likely causes of variation in methane concentration for repeat sampling include where the sample is drawn from the system, the volume of water purged before collecting the sample, and natural variation over time (modified from Molofsky et al., 2018). Three sample collection techniques commonly use in sampling domestic and farm wells in the USA are shown. a) Direct filling of Volatile Organic Analysis vials (VOA). b) Inverted filling of VOA. d) Collection using an IsoFlask® commercial sample collector sold by Isotech (adapted from Molofsky et al., 2016).

Effervescing samples were those with higher methane concentrations that required closed-system sampling. Such samples may indicate that a free-gas phase is present in the water well. Effervescence—i.e., the turbulent exsolution of the dissolved gas from a groundwater sample—reflects the depressurization of the sample when exposed at ground surface (lower pressure) or within the water well itself during drawdown of the water level (Humez et al., 2016). This is the most explicit example of loss of analyte (gases) from the collected sample.

When a free-gas phase is present, the meaningful measurement of the gas content of groundwater becomes much more complex as Roy and others (2022) show in a study from Québec, Canada. For this situation, the use of total dissolved gas pressure (TDGP) probes is essential and should be coupled with the measurement of total water pressure, electrical conductivity, and total gas composition (Morais et al., 2022). Fleming and others (2022) described how the fugitive gas migration emissions vary with micrometeorological variables such as wind speed and barometric pressure. More recently, Morais and Ryan (2023) have investigated the in-well degassing of monitoring wells in gas-rich aquifers with TDGP probes and determined that in-well degassing is a response to bubble exsolution as groundwater moves upwards within the monitoring well due to hydraulic-gradient and/or thermal-gradient driven convection.

The use of domestic and farm water supply wells without gaining access to the well itself eliminates the possibility of accurate measurement, as indicated by Roy and Ryan (2010). Why? Because any in-well degassing is not observed, and the evolved gas is lost to the analysis. Therefore, the reported concentrations obtained from sampling dissolved gases at the end of a water-well system (e.g., Figure 39) that include a submersible pump, pressure tank, and faucet are necessarily *concentration estimates*, in the terminology of Ryan and others (2015), particularly when the sample is effervescing. Not surprisingly, the highest measured concentration estimates from the methods shown in Figure 39 are from the closed IsoFlask® container (Molofsky et al., 2016), which yielded "significantly higher methane concentrations" than the other methods shown (p. 669). Ashmore and others (2022) explain how analytical results from such data can be interpreted to yield various gas ratios for the component gases and subsequently to indicate the thermogenic or microbial origin of the sampled gas.

The problems with sampling domestic and farm water wells are well known; there is the possibility that the wells are contaminated by nearby septic tanks, farmyard wastes, or road salt from highway de-icing (Jackson & Heagle, 2016). While this is certainly a problem in trying to establish the groundwater quality (GWQ) associated with natural groundwater evolution and water-rock interaction, it is not an issue in determining if the water well is contaminated by natural gas because a hydrogeologist would be able to identify from the multicomponent nature of the chemical analysis the presence of highway de-icing salt or human or animal wastes—such as diagnostic *E. coli*. However, any detected natural gas may be from either shallow gas-rich bedrock or from a leaking gas well nearby or both. Ironically, domestic and farm wells may provide vents for such gas to escape from the subsurface.

6.1.2 Baseline Groundwater Quality Monitoring

It is specified in many oil-and-gas producing jurisdictions that landowner or domestic and farm water supply wells near unconventional gas wells—e.g., 0.5 km to 1 km—must be sampled and analyzed for a range of water-quality parameters, including hydrocarbon gases and their isotopes, major ions, pH and redox parameters—Eh, O_2, H_2S—prior to and following drilling of a nearby well. This is a prudent requirement that may detect failures in newly drilled energy wells or in releases from poorly constructed, producing, or legacy wells.

The oil and gas industry identifies this sampling as a risk management tool, and to hydrogeologists, this forms part of the development of a baseline GWQ program to help determine (i) if fugitive gases have invaded domestic or farm wells and led to the deterioration of GWQ, or (ii) if methane is naturally present in the shallow sediments—e.g., in shales or coal beds. Here we use the US Geological Survey definition of baseline GWQ meaning the starting point of monitoring, such as a pre-drilling measurement (API, 2009), and which typically includes some influences of human activities (Lee & Helsel, 2005). Regulators are interested in the protection of high-priority aquifers and rely on rating systems, such as DRASTIC, and Geographical Information Systems (GIS) analysis to focus protection on those shallow aquifers most susceptible to contamination (Bedessem et al., 2005).

The nature of any baseline GWQ monitoring program will depend a great deal on whether purpose-built monitoring wells are available as part of the network. If not, it is most probable that the sampled water wells will be *landowner* or *residential* wells—i.e., domestic and farm water supply wells. It is important that these be monitored as they are most often the closest sampling locations to the gas-well operations, e.g., Hammond's (2016) study around Dimmock Township, Pennsylvania, USA. Furthermore, because the water supply wells are often drawn down with respect to the local water table, they may act as sinks and vents for fugitive gases and consequently would be appropriate sampling locations, although the source of the gases will remain undetermined.

The methods developed by Molofsky and others (2016) were prepared to develop recommended practices for improved sample collection methods and data interpretation for pre-drill and post-drill sampling programs. They note that, by sampling at the outlet of the pressure tank connected to a water well, exsolution of dissolved gas during pumping must be anticipated. Therefore, in the terminology of Roy and Ryan (2010), these are *concentration estimates* subject to underestimation when reported values exceed 20 mg CH_4/L and when the sample is effervescing.

In any baseline GWQ monitoring program, it is necessary to consider the temporal variability in measured gas concentrations in water wells, which was documented by Gorody (2012) and further shown by Hammond (2016). Consequently, several sampling campaigns at different times of the year are needed to establish the variability in baseline natural gas concentrations and therefore establish a range of ambient concentrations. This point was emphasized by Humez Mayer, Nightingale, Ing, and others (2016), who studied an eight-year record of one monitoring well in Alberta, Canada, completed in a coalbed methane deposit. Their study of free-gas versus dissolved-gas partitioning provides further evidence that lowering the head in a water well results in significant methane degassing of the water. This decrease in water level thus increases the free-phase methane concentration at the expense of the dissolved-phase concentration. They further noted that, although methane partitioning was mainly influenced by the flow rate and depth of the submersible pump, this did not seem to affect the methane isotope composition.

The free-phase gas that migrates in the annular space behind a gas-well casing readily penetrates fractures in bedrock because of low capillary entry pressures (Dusseault et al., 2000; Dusseault & Jackson, 2014) and then migrates (buoyantly) through the fracture network (Gorody, 2012). Because of gas slugging behind the casing and capillary entry pressures associated with gas-soil interaction, there will be gas pulses, causing variability in the measured natural gas concentration, including concentrations that exceed methane saturation at ambient temperatures (~30 mg/L in fresh water at 101 kPa), as was shown by Hammond (2016). Consequently, Gorody (2012) recommended that baseline GWQ monitoring should involve more than a single sample from each water well. McMahon and others (2019) show that, because of the length of flow systems and the velocity of groundwater flow, evidence of leaking gas wells may only occur in monitoring wells after many years; Dusseault and Jackson (2014) and Dusseault and others (2000) arrived at the same conclusion.

Through oxidation of fugitive gas, methane is converted to aqueous carbon dioxide in the form of bicarbonate—dissolved inorganic carbon—and a lowering of the pH. This can cause in-situ weathering and change the groundwater quality of inorganic species through pH and redox reactions. Bondu and others (2021) identify best practices for measuring inorganic baseline parameters. Shaheen and others (2022) used methane and chloride in areas of Pennsylvania to identify the effects of shale-gas development and found that chloride—whether from well-pad releases or from subsurface sources—was an indicator of local groundwater contamination. Road-salt chloride was not mentioned (Jackson & Heagle, 2016). Therefore, of the potential inorganic contaminants, chloride measurements should be carefully interpreted. Baseline GWQ monitoring is often initiated only after oil and gas development has begun and questions arise as to what the pre-drill baseline of methane might have been. However, several exemplary baseline GWQ monitoring studies have been completed prior to nearby shale development in Texas, USA, by Nicot, Larson and others (2017) and Nicot, Mickler and others (2017); in Alberta, Canada, by Humez, Mayer, Nightingale, Ing, and others (2016); in Québec Canada, by Rivard and others (2018a) and Bordeleau and others (2018, 2024). These likely represent natural conditions—i.e., pre-drill samples—and show how gas concentrations and isotopic patterns are used to determine natural or anthropogenic influences in terms of organic species and their isotopes.

The advent of HF stimulation had profound implications for GWQ monitoring in major producing regions resulting in GWQ regulations that have been either much enhanced or implemented for the first time. In California, USA, the state implemented an oil and gas monitoring program in 2014 to assess potential impacts to groundwater associated with HF stimulation in the state's mature oil and gas industry.

While the shallow aquifers near Californian oilfields had been delineated earlier, Kang and Jackson (2016) investigated the use of higher salinity deep groundwater beneath the Central Valley of California showing that the volume of usable groundwater can be increased by a factor of four if depths to 3,000 m are considered. However, the potential for contamination of this slightly saline but usable groundwater was threatened by oilfield pumping and injection into depleted reservoirs—e.g., waterflooding.

This study was complemented by the US Geological Survey (USGS) that investigated the distribution of groundwater near oil fields having total dissolved solids less than 10,000 milligrams per liter (mg/L) based on available data (Metzger and Landon, 2018). Once more it was felt that groundwater of this salinity could one day have beneficial uses other than for waterflooding. Stephens and others (2019) discussed geophysical salinity mapping using downhole resistivity measurements correlated with measurements of total dissolved solids (TDS) in groundwater samples from various oil and water wells.

Research under the California, USA, oil and gas monitoring program has continued with the USGS conducting surveys of groundwater salinity in the hydrocarbon reservoirs of southern California (McMahon et al., 2017; Gillespie et al., 2017). The principal objective of the most recent USGS work has been to identify tracers—chemical, isotopic, and age-dating species—that might be measured in an anticipated groundwater monitoring program that the state of California intended to create. Understanding the mixing of groundwater and fluids from hydrocarbon reservoirs requires that the geochemical signatures of the water end members be established. End members for three Californian oil fields have been reported by McMahon and others (2018).

The focus of the USGS has most recently turned to understanding aquifers where fluids from the hydrocarbon reservoirs have mixed with groundwater (McMahon et al., 2024). This study of two oil fields and their adjacent groundwater identified the following major data limitations for groundwater monitoring under the California oil and gas monitoring program.

1. Especially, monitoring wells may be absent for some depths and locations which are at a high risk of hydrocarbon fluid migration.
2. Mixing calculations may be inhibited by a lack of end member signatures, whether it is shallow groundwater or oil-field water.
3. Certain high-risk areas may lack a sufficient time-series record of groundwater elevations and groundwater quality (this was also noted by Stanton et al., 2023, for their inconclusive study of GWQ near the Montebello, California, oil field).
4. As Lackey and others (2021) also noted, the formatting of public databases of hydrocarbon wells, their associated completion and testing logs, and their injection-production data are not necessarily readily compiled into electronic databases.

6.2 Atmospheric Emissions

Measurements of methane and other gas emissions can be used to estimate methane emission rates and to identify leaks so that they can be fixed. It is important to note that leak identification does not require methane emission rates to be quantified; in practice, methane and other combustible gas detectors are used to detect methane concentrations above background levels to identify the leaky component. Methane is well-mixed in the atmosphere; globally, methane concentrations of ~2 ppm in air are typical (IPCC, 2014). The differences in elevated methane concentrations and the background of ~2 ppm are referred to as methane *enhancements*. Although such enhancements do indicate the presence of a methane source, the concentration levels alone do not provide enough information to determine methane emission rates or to identify the emissions source.

There are a wide range of methods for measuring methane emission rates to the atmosphere; the method used depends on the objective of the emissions estimate, and on the magnitude and scale of the emissions source. The National Academies of Science, Engineering, and Medicine (2018) summarized spatial and temporal scales of measurement methods from individual sources (<1 to 10 m^2), to the facility or site scale (<1 to 10 km^2), to intermediate scale regional (10 to 100 km^2), and on to continental scale surveys (1000s of km^2) over periods of seconds to years. At the individual source scales, enclosure-based measurements (e.g., Kang et al., 2014) or high-flow samplers (e.g., Saint-Vincent et al., 2020) can be applied over seconds to days. At the facility or site scale, mobile measurement systems with instruments mounted on vehicles can be used in addition to chamber-based measurements. At regional and continental scales , aircraft, towers, and satellites become preferred measurement platforms. Small-scale platforms have the lowest detection limits, and most surface emissions are detected using local-scale methods—e.g., chamber-based methods.

Emission factors—essentially mass or volume of gas emitted per component per time—are based on such local-scale or individual source measurements. Emission factor-based methods are currently used to estimate methane emissions from abandoned oil and gas wells and surface casing vent flows of both active and abandoned wells. Individual source methods are labor-intensive and methane emissions over large areas are difficult to estimate; however, though large-scale platforms can cover substantial areas quickly, they may miss many low-emission sources such as abandoned wells. The other challenge of large-scale platforms is the difficulty of attributing emissions to a source. Nevertheless, there have been many advances in remote methane detection methods and there is potential for aerial surveys to complement individual source measurements (Pozzobon et al., 2023).

Top-down measurements occur at larger scales than bottom-up measurements. Typically, methane estimates based on emission factors derived from individual sources and facility/site-scale measurements are viewed as bottom-up, whereas aircraft/towers/satellite measurements are viewed as top-down measurements. In general, top-down measurements capture multiple sources within the target area, whereas bottom-up estimates rely on the completeness of lists of methane sources.

Numerous studies have shown that methane concentrations in oil and gas regions using top-down methods do not align with those determined using bottom-up estimates (Miller et al., 2013; Pétron et al., 2014). These comparisons typically rely on government inventories such as the one at the US EPA for their bottom-up estimates. The major finding is that government inventories are likely incomplete with missing and underestimated sources. These differences can be reconciled by improving bottom-up inventories (Zavala-Araiza et al., 2015, 2017).

The subsurface origin of emitted methane may be identified using geochemical tools, including presence and concentrations of co-emitted gases—hydrocarbons and other gases such as CO_2—isotopes of methane and other co-emitted gases and the presence and isotopic composition of noble gases which are highly conservative (Darrah et al., 2014; Kang et al., 2016). Such geochemical tools have been helpful in identifying whether the source of the emissions is thermogenic—linked to natural subsurface migration or oil and gas production—or biogenic—generally considered to be microbially-produced methane such as those from wetlands or coalification processes. Using geochemical tools, it may be possible to differentiate subsurface-based emissions from methane emissions from surface oil and gas activities—e.g., venting, storage tanks.

Most surface emissions from abandoned wells—due to subsurface leakage—are measured at the local or individual source scale (e.g., Forde et al., 2019c; Kang et al., 2014). Therefore, we present a brief description of enclosure-based or chamber-based methods, using abandoned well emission measurements as an example.

Chamber-based methods are individual source or local-scale methods that involve an enclosure of the emissions source—e.g., well—and measurements of concentration changes in the enclosure over time. The advantage of these methods is that the emission source is known, and atmospheric processes can be effectively ignored. There are two types of chamber-based methods, static—non-steady-state—and dynamic—steady-state. Static chambers allow emitted gases to accumulate; dynamic chambers involve continuous pumping of a known gas—e.g., air or nitrogen—at constant rates through the chamber (Livingston & Hutchinson, 1995). A common reason for using static chambers is (Figure 40) because fewer components—pump, gas tank, extra batteries—are needed compared to dynamic chambers, allowing for measurements at remote locations in challenging terrain. However, abandoned wells have also been measured using dynamic chambers and high flow samplers. Chamber-based methods can measure the full range of methane emission rates observed at abandoned wells, whereas high flow samplers are designed to quantify relatively high emitters and not necessarily low emitters or methane uptake. Williams and others (2023) have undertaken controlled testing of the static chamber method and found errors to be +/-14%, which can be reduced to +/-5% with optimal configurations.

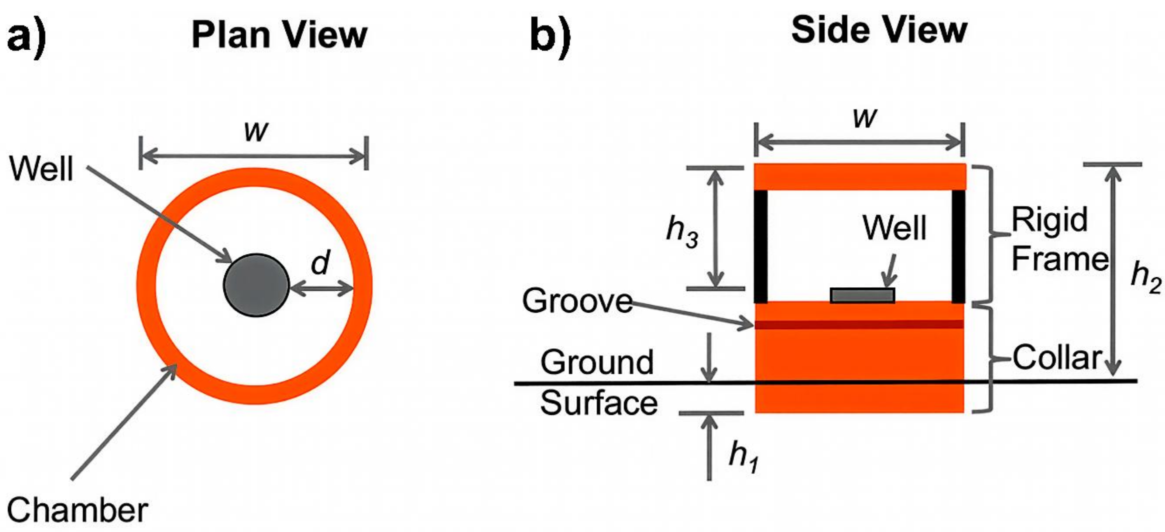


Figure 40 - Schematic of flux chamber collar and frame enclosing surface protrusions of an abandoned oil and gas well. All variables other than the chamber diameter, w, depend on location (adapted from Kang and others, 2014, supporting Information, Figure S1).

For abandoned wells in Pennsylvania, USA, the entire footprint and any surface protrusions were enclosed in the chamber (Kang et al., 2014; Kang et al., 2016). The chamber was sealed to the ground such that emissions from various leakage pathways in and around the well, i.e., annulus and casing—were captured. Schout and others (2019) illustrate their use in The Netherlands to determine emissions from abandoned wells that were cut and buried to ≥ 3 m bgs.

This is different from surface casing vent flows which do not capture leakage outside of the casing. In addition, methane emission rate measurements were made in soils surrounding abandoned wells to obtain an approximation of *background* or *control* emission rates. Gas samples were collected from the chambers and were analyzed in the laboratory using gas chromatography and laser-based sensors for methane, ethane, propane, n-butane, stable carbon and hydrogen isotopes of methane, and noble gases. Additionally, mobile sensors (such as a Picarro™) can be used to measure methane and other select gases and isotopes directly in the field. The additional geochemical information was used to identify the origin of the emitted methane as microbial, thermogenic, or mixed microbial/thermogenic. Definitions of these terms are provided by Whiticar (1999). The additional geochemical information may also be used to identify methane-source formations and provide insight into leakage processes.

7 Numerical Simulation of Fracturing and Subsurface Gas Migration

In recent years, there has been considerable effort devoted to modeling the environmental impacts of natural gas production, especially unconventional gas production. In this context, there are several themes which have been addressed, as follows.

- **Transport of Hydraulic Fracturing Fluids:** How do hydraulic fracturing fluids propagate through permeable pathways—e.g., open natural fractures, transmissive faults, and thief zones? How do interactions with reservoir and caprock formations, such as imbibition and diffusion, impact the movement and spread of hydraulic fracture fluids?
- **Subsurface Pathways for Methane Flow:** What are the potential pathways for methane migration? What are the realistic thresholds for parameters such as permeability—or capillary entry pressures—at which gas flow will occur? These studies have focused on natural fracture systems, hydraulically stimulated fractures, and oil and gas wells.
- **Fracture Propagation and Reactivation:** How do stimulated fractures propagate? What is the maximum vertical extent of such fractures? How do natural fractures become re-activated by fracking operations? Could they become permeable pathways connecting hydrocarbon-producing zones to shallow aquifer systems?
- **Wellbore Stability:** How do the mechanical, thermal, and chemical processes occurring in deep wellbores affect wellbore stability? How do construction materials such as cement and steel behave in such environments?
- **Environmental Impacts of Methane in Aquifers:** How does methane gas react in a groundwater environment? How readily does it degrade, and what changes in groundwater chemistry may be expected?

Some of these themes overlap, and many of the numerical studies in the scientific literature examine multiple aspects of natural gas development and production. The following sections provide a brief overview of various numerical modeling studies and their conclusions regarding natural gas propagation and environmental contamination.

7.1 Transport of Hydraulic Fracturing Fluids

In an early paper, Myers (2012) examined the potential for migration of hydraulic fracture fluid and formation brine through a hypothetical pre-existing natural fracture network using a MODFLOW model. This paper was roundly criticized in comments by Saiers and Barth (2012) and Cohen and others (2013) for poor assumptions, inadequate understanding of physical processes—namely multiphase flow, but also unrealistic boundary conditions, and calculation errors.

Subsequently, numerous authors have corrected many of these problems. Cai and Ofterdinger (2014) studied chloride flux—but not methane transport—in a hydraulically fractured Bowland shale in the United Kingdom. They found that unless very large—1 mm aperture or larger—fractures were generated, hydraulic fracturing of the Bowland shale was unlikely to pose a risk to groundwater quality due to brine migration.

Birdsell and others (2015) performed a parametric study which focused on the transport of HF fluid on a timescale of 1000 years and illustrated behavior of an *extreme end-member scenario* in which a single permeable pathway connects the shale gas reservoir to a freshwater aquifer. They modeled HF fluid transport as a single-phase process using the Finite Element Heat and Mass Transfer code (FEHM). To approximate the effects of capillary suction in a reservoir with significant gas saturation, they modeled imbibition as a sink-term that is active for five days. They found that the buoyancy of HF fluid—as compared to basin brine—was relatively unimportant. The reservoir overpressure during stimulation had highly varied effects on HF fluid movement. Imbibition and gas-well production substantially reduced the risk of aquifer contamination by HF fluid.

7.2 Subsurface Pathways for Natural Gas Flow

Other modelers have focused on the flow of gas, using sensitivity analyses to establish how gas moves from a source zone along permeable pathways and identifying the parameter space within which gas seepage to shallow aquifers is possible. Using TOUGH+RealGasH2O, Reagan and others (2015) performed a parametric study of processes and parameters that could cause rapid transport of gas—and water—into shallow aquifers. The study focused on failure scenarios involving fractures—both HF-generated and pre-existing—and gas wells—both production and abandoned. They found that the most important parameters were permeability and volume of the connecting feature. Well annulus permeabilities less than 10^{-15} m^2 were shown without exception to not support gas flow. The authors did not comment on the likelihood of the given scenarios.

In another sensitivity analysis, Zhang and others (2014) focused on the problem of leakage from a well in a hypothetical system, based on the US DOE Greene County study in Pennsylvania, USA, as discussed in Section 5.2. Using TOUGH2-EOS7C, the authors attempted to answer the question of whether such a leak could be detected in an offset monitoring well, and under what circumstances. The model is a single-phase simulation, assuming that water saturations in the studied formation are immobile. Their base case yielded a 10-year detection time at the monitoring well that was most strongly affected by the thickness of a high-permeability bed situated 35 m above the leak point of the Marcellus gas well, the rate of pumping at the monitoring well, and the leakage rate of natural gas from the gas well.

Nowamooz and others (2015) used an alternative modelling code, DuMuX, to perform a sensitivity analysis of leakage from a decommissioned shale gas well and provided an excellent summary of the issues. The model had a simple radial geometry, assumed that the still pressurized target formation was the likely source of leaking gas, and assumed uniform degradation of the entire wellbore. The most important parameters were found to be cement permeability, source formation permeability, and source zone gas saturation and pressure. In agreement with Reagan and others (2015), the authors found that wellbore permeabilities less than 10^{-15} m^2 prevented significant leakage. They also assessed the potential for brine leakage, finding no major impacts on groundwater quality. Roy and others (2016) also used this multiphase simulator to model gas migration coupled with biodegradation modeling for the Lindbergh, Alberta, Canada, case history discussed in Section 4.1.4.

In a near-surface model application, Zhang and Soeder (2015) used TOUGH2 to model methane migration during drilling in a shallow aquifer. They concluded that reported increases in groundwater methane concentrations near shale gas production wells may be due to the transport of pre-existing—i.e., naturally present—methane by groundwater surges induced by air-hammer drilling (Figure 19; Geng et al., 2013).

7.3 Fracture Propagation and Reactivation

Several groups have investigated fracture propagation and fault re-activation using hydromechanically coupled models. Rutqvist and others (2013, 2015) used numerical modeling (TOUGH-FLAC) to study whether shallow groundwater systems were likely to be contaminated by leakage through natural fault systems reactivated by hydraulic fracturing in the Marcellus Shale, similar to the scenario investigated by Myers (2012) but using a much better conceptual model and understanding of the relevant physical processes. They found that the likelihood is remote that hydraulic fracturing at a depth of 1 mile (1.6 km) would cause a significant reactivation of natural fault systems and create permeable pathways linking the gas production zone to shallow aquifers. This adds to field observations by authors such as Davies and others (2012) and Flewelling and others (2013) in countering the notion that high vertical fracture growth is a potential gas seepage pathway caused by hydraulic fracturing.

Konstantinovskaya and others (2014) also used TOUGH-FLAC to examine fault reactivation during CO_2 injection, a somewhat related problem. The authors found that fracturing of the permeable host rock occurred only under extremely high injection rates—and that it was localized below the caprock—preventing upward CO_2 migration. Kim and Moridis (2015) modeled vertical fracture propagation by tensile fracturing, coupling their ROCMECH geomechanics simulator with TOUGH+RealGasH2O. They found that a geological layer of greater stiffness within the caprock could effectively prevent vertical fracture propagation, diverting vertical fractures in a horizontal direction. Valiveti and others (2015) provided another example of a hydraulic fracture propagation model using the Generalized Finite Element Method. Ji and others (2009) provided a further example, using their coupled Reservoir and Geomechanics Simulation Model.

Because of the complexity and strongly coupled interactions between processes, most hydraulic fracturing models developed to date are limited to simple geometries. These models often focus on fracture propagation in the target zone, rather than the overlying cap rock. There are many papers describing efforts to model hydraulic fracture propagation.

7.4 Mechanical Stability of Oil and Gas Wells

Another focus of modeling efforts has been the mechanical stability and permeability of the wellbore itself. Schreppers (2015) advocated a complete analysis of casing and cement mechanical stability, accounting for loadings during the construction phases and typical loadings during operation—both mechanical and thermal. This scheme was implemented using the mechanical modeling code DIANA. In slightly different approach, TerHeege and others (2015) used the discrete element model PF3D to simulate failure and damage of wellbore cement and surrounding rock. They studied the critical stress conditions and injection pressure limits for damage initiation, looking at the effect of radial expansion of casing from pressurized fluids in the casing. They also addressed radial compression of casing and cement—due to rock deformation, or from pressurization and depressurization inside the casing; axial deformation of casing and cement—due to reservoir expansion; and changes in horizontal stress in the reservoir and caprock. Although this study focused on the mechanical impacts of increased reservoir pressure on a wellbore, a similar approach could be used to examine mechanical processes of more relevance to operational or abandoned wellbores.

To explore the possible development of microannuli in a cemented wellbore with a focus on the effect of cement shrinkage, Oyarhossein and Dusseault (2015) presented a simple model to examine stress changes around a wellbore. They found that the development of these permeable pathways was highly influenced by the maximum degree of cement shrinkage, the elastic properties of the adjacent formation, and the deviatoric stress magnitude. Using realistic parameters, they found that the development of microannuli in a cemented wellbore is possible, and even likely, given the right conditions, as the radial compressive stress drops below the local pore pressures, leading to a condition promoting induced tensile fracturing when the radial total stress dropped below the pore pressure because of cement shrinkage. Schreppers (2015), TerHeege and others (2015) and Oyarhossein and Dusseault (2015) are just three recent examples of the many papers examining the geomechanical stability of wellbore casing and cement. Vrålstad and others (2019) illustrate the development of gas-migration pathways with x-ray computed tomographic visualizations of experimentally obtained non-uniform microannuli.

7.5 Environmental Impacts of Methane in Aquifers

The environmental effects of methane gas propagation in aquifers have also been studied by numerical simulation. Using a combination of DuMuX and BIONAPL/3D, Roy and others (2016) simulated the degradation of methane in a shallow aquifer under sulfate-reducing conditions. They found that aquifers high in sulfate may be less vulnerable to methane contamination but may have finite attenuation capacity (Section 4.1.4 discusses related material).

Bouznari and others (2024) simulated the sand-tank experiment of Van De Ven and Mumford (2020a) shown in Figure 32 and Figure 33. They discuss the relative merits of kinetic and equilibrium approaches to field-scale simulations of methane migration. They conclude that the kinetic approach is likely required for interpreting lab-scale experiments; however, because dissolved methane concentrations tend towards equilibrium, a kinetic approach is shown to be unnecessary for field-scale simulations.

8 Summary and Conclusions

This book reviews exploration and production operations in the oil and gas industry to allow hydrogeologists to appreciate how hazards to potable groundwater and water wells can arise from these activities. Without such an understanding, it is difficult for hydrogeologists and water-resource regulators, who might have little or no experience of oil and gas exploration and production operations, to appreciate how contamination at (1) well pads and (2) from fugitive gas from leaking wells can cause groundwater contamination and atmospheric emissions.

At well pads, it is principally the surface handling and storage of produced brackish water and brine, as well as aqueous fracking fluids and related materials that create groundwater contamination incidents of the kind well known in contaminant hydrogeology. The problem of fugitive-gas migration to water wells is an entirely new category of study—arising since 2010—that is only beginning to be appreciated through forensic studies, experimental field investigations, and numerical simulations.

It has been argued that there is a critical lack of field studies that allow hydrogeologists to understand, simulate, and perhaps prevent groundwater contamination arising from shale-gas production (Jackson et al., 2013). Two particular areas of ignorance with respect to groundwater contamination stand out: “(1) baseline geochemical mapping (with time series sampling from a sufficient network of groundwater monitoring wells) and (2) field testing of potential mechanisms and pathways by which hydrocarbon gases, reservoir fluids, and fracturing chemicals might potentially invade and contaminate useable groundwater” (Jackson et al., 2013, p. 488). Networks of regional monitoring wells remain largely absent in North America with some major exceptions in Canada. Field experiments are few and far between but have proven exceptionally helpful in understanding processes. Much work remains for hydrogeologists, and there is large potential to combine ongoing measurement efforts in the atmospheric methane measurement and modeling community to improve our understanding of subsurface leakage from oil and gas development.

9 Exercises

Exercise 1

Figure 13 shows a fault that is intercepted by a well at approximately 1300 ft depth. Assuming that the well annulus surrounding the casing is filled with a 1000 ft column of brine above the fault with a density of 1100 kg/m^3, what is the brine pressure, p, at the point of intersection of the fault with the uncemented casing annulus? Please report in SI units. It is helpful to remember that $p=\rho gh$, where ρ is the fluid density, g is the acceleration of gravity, and h is the height of the column of fluid Static fluid gradients are illustrated in Figure 10b).

The pressure at 1300 ft depth is at least the weight of 1000 ft of brine. In evaluating the problem, ignore the pressure exerted by the gas cap on the brine beneath the bradenhead valve, which is negligible in terms of the accuracy of this calculation.

Solution to Exercise 1⤵

Return to where text linked to Exercise 1⤴

Exercise 2

The bradenhead gauge pressure in Figure 13 is recording 100 psi or ~ 700 kPa, which is a result of the degassing of the annular column of brine in the borehole. Gas buildup at the wellhead has been implicated as potentially promoting gas leakage around the surface casing shoe—if a permeable pathway exists. If the surface casing vent valve were opened allowing the gas pressure in the production casing annulus to drop to atmospheric pressure, what would happen to fluid levels in the well? Would this serve to mitigate the flow of methane and/or methane saturated brine into the intersecting fracture at 1200′? Use metric units for the analysis and assume: the gauge pressure is 700 kPa; atmospheric pressure is 100 kPa; brine density is 1100 kg/m^3; the gas is pure methane; and the small pressure and density gradient in the methane column can be neglected.

Solution to Exercise 2⤵

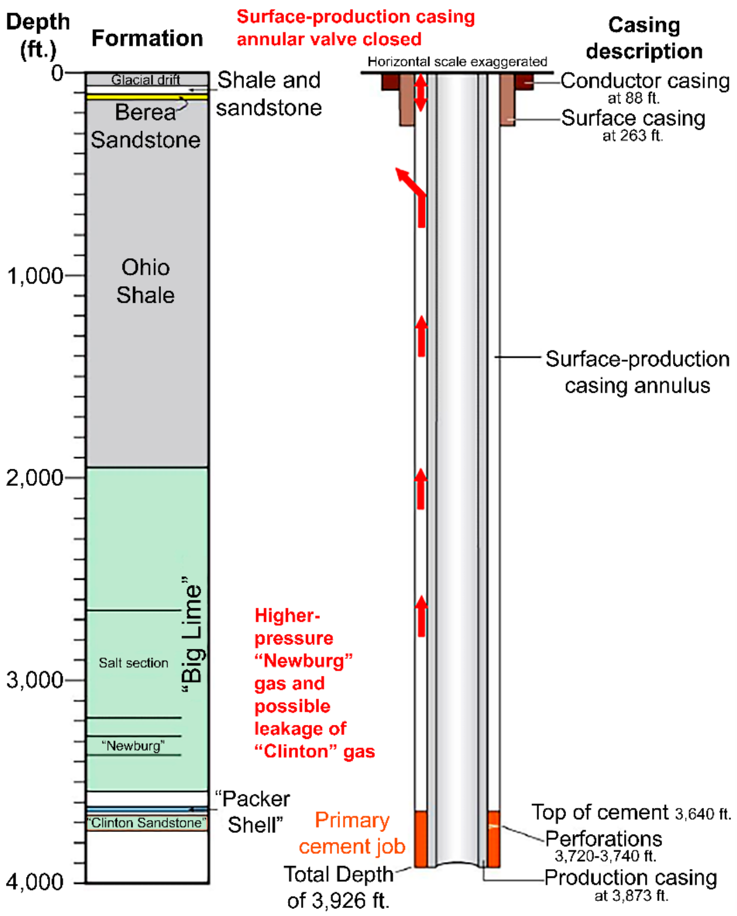
Return to where text linked to Exercise 2⤴

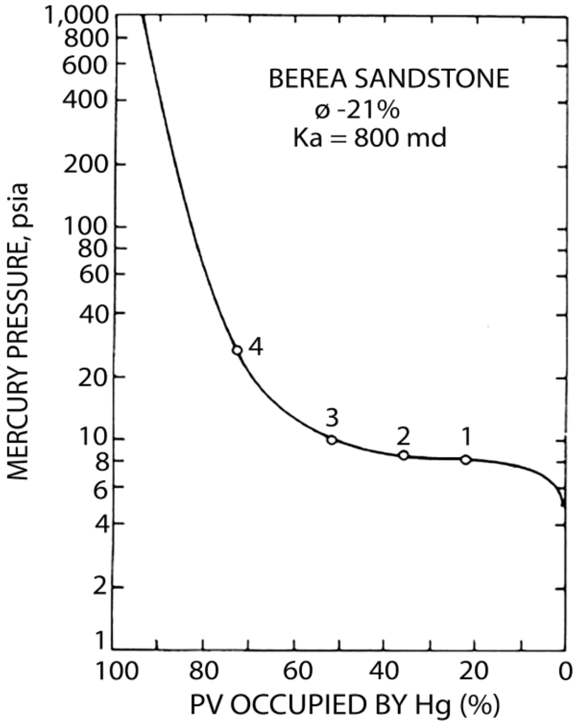
Exercise 3

The image shown below is a schematic of a leaking gas well in Ohio discussed by Bair and others, (2010) and shown as Figure 24. Leaking gas from depth causes the contamination of water wells in the Berea Sandstone by migrating upward along the wellbore annulus as shown and into the bedding plane fractures that have an entry pressure (P_e) essentially equal to zero psi, that is, there is no capillary resistance to their invasion because of the size of the fracture apertures. The second image shows a mercury intrusion capillary pressure curve of a sample of Berea sandstone matrix.

Let's define the P_e into this block of sandstone at ~1% of the pore volume (PV) occupied by mercury (Hg), i.e., the threshold entry pressure. From the second image, the Hg P_e is approximately 6 psi. Let's assume the borehole casing annulus pressure is equal to the shut-in pressure, $P_{shut\text{-}in}$ = 320 psi, with the pressure caused by leakage of natural gas from the deep gas reservoirs into the annulus. The interfacial tension can be looked up in a reference manual (e.g., Vavra et al., 1992) and σ_m and σ_{Hg} are approximately 0.07 N/m and 0.5 N/m, respectively.

Question: Is this annulus pressure sufficient to cause the gas to enter the pores of the sandstone? Discussion in Section 3.1.3 and Section 4.1.3 may be helpful in this evaluation.





Solution to Exercise 3

Return to where text linked to Exercise 3

Exercise 4

Figure 25 illustrates the extent to which natural gas might migrate under some conditions in soil. Gas migration has been historically measured within a meter of a well casing. How would you establish an improved evaluation scheme to determine gas migration away from any legacy well? The discussion presented in Section 4.1 may be helpful in considering how to improve the approach to determining gas migration from a legacy well.

Solution to Exercise 4

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11 Exercise Solutions

Solution Exercise 1

This is a "static fluid head" problem. Therefore, $p=\rho gh$, where ρ is the fluid density, g is the acceleration of gravity, and h is the height of the column of fluid. The fluid column is approximately 310 m high, therefore:

$$p = \left(1100\,\frac{\mathrm{kg}}{\mathrm{m}^3}\right)\left(9.8\,\frac{\mathrm{m}}{\mathrm{s}^2}\right)(\,310\ \mathrm{m}) \;= 3.3\mathrm{x}10^6\ \mathrm{Pa} \;= 3.3\ \mathrm{MPa}$$

Return to Exercise 1↥

Return to where text linked to Exercise 1↥

Solution Exercise 2

The short answer to this question is: "No, this would not mitigate flow into the intersecting fracture."

It is reasonable to assume that the gas pressure is in equilibrium with brine pressure in the annulus, which is dominated by the most permeable fractures or formations intersecting the open hole. When the gas pressure is released, the brine level will rise until it reaches a new equilibrium, at a level where the initial brine pressure at the gas-brine interface (700 kPa at 1200′ [365.9 m] depth) is restored.

Prior to releasing the gas pressure in the production casing annulus, the pressure at the 1200′ deep fracture intersection is calculated as follows.

$$P_{@frac-closed\ valve} = 100\ \text{kPa} + 700\ \text{kPa} + \frac{\left(1100\ \frac{\text{kg}}{\text{m}^3}\right)\left(9.81\ \frac{\text{m}}{\text{s}^2}\right)(365.9\ \text{m} - 70.1\ \text{m})}{1000\ \frac{\text{Pa}}{\text{kPa}}}$$

$$= 3991\ \text{kPa}$$

After the gas is released, the brine will rise to a new equilibrium. The increased height of the brine column is as follows.

$$H_{brine} = \frac{(700\ \text{kPa})1000\ \frac{\text{Pa}}{\text{kPa}}}{\left(1100\ \frac{\text{kg}}{\text{m}^3}\right)\left(9.81\ \frac{\text{m}}{\text{s}^2}\right)} = 64.87\ \text{m}$$

After reaching this new equilibrium the resulting pressure at the fracture as follows.

$$P_{@frac-open\ valve} = 100\ \text{kPa} + \frac{\left(1100\ \frac{\text{kg}}{\text{m}^3}\right)\left(9.81\ \frac{\text{m}}{\text{s}^2}\right)(365.9\ \text{m} - 70.1\ \text{m} + 64.87\ \text{m})}{1000\ \frac{\text{Pa}}{\text{kPa}}}$$

$$= 3991\ \text{kPa}$$

Hence the driving force pushing methane saturated brine into the intersecting fracture will not change if gas pressure in the production casing annulus is released.

Return to Exercise 2↥

Return to where text linked to Exercise 2↥

Solution Exercise 3

First it is necessary to convert the P_e determined by mercury intrusion into what it means in terms of natural gas invading the groundwater-wet Berea Sandstone matrix and add it to the pore pressure in the sandstone. Then this can be compared to the shut-in gas pressure measured at the wellhead, $P_{shut\text{-}in}$ = 320 psi.

Converting $P_{shut\text{-}in}$ to SI units, there are 0.145 psi per 1 kPa, and $P_{shut\text{-}n}$ is 320 psi

$$\frac{320\ psi}{\frac{0.145\ psi}{1kPa}} = 2207 \text{ kPa and rounding provides } P_{shut\text{-}n} \sim 2200 \text{ kPa}$$

To convert the air/Hg mercury intrusion pressure to that of groundwater/gas intrusion pressure within the Berea Sandstone matrix, we use the following relationship

$$P_m = P_{Hg}\ \frac{\sigma_m \cos\theta_m}{\sigma_{Hg}\cos\theta_{Hg}}$$

P_m is the capillary entry pressure of gas into the sandstone matrix

P_{Hg} is the capillary entry pressure of Hg into the sandstone matrix

σ_m and σ_{Hg} are the interfacial tensions of the Berea matrix groundwater/gas and laboratory air/mercury systems, respectively

$cos\ \theta_m$ and $cos\ \theta_{Hg}$ are cosines of contact angles of the Berea matrix groundwater/gas/matrix and laboratory air/mercury/matrix, respectively

Converting P_{Hg} to SI units, there are 0.145 psi per 1 kPa, and P_{Hg} is ~6 psi

$$\frac{6\ psi}{\frac{0.145\ psi}{1kPa}} = 41.37 \text{ and rounding provides } P_{Hg} = 40 \text{ kPa}$$

The cosine of the contact angles are

$\cos\theta_m = \cos 0^0 = 1$ (that is, the gas does not wet the matrix)

$\cos\theta_{Hg} = \cos 140^0 = |-0.77|$ (that is, the Hg wets and spreads into the matrix)

$$P_m = 40\text{ kPa}\ \frac{0.07\frac{\text{N}}{\text{m}}(1)}{0.5\frac{\text{N}}{\text{m}}(|-0.77|)} = 7.3\text{ kPa}$$

The Berea sandstone occurs at about 100 ft (30 m) depth, so assuming fresh water, hydrostatic pressure is as follows.

$$p = \rho g h = \left(1000\frac{\text{kg}}{\text{m}^3}\right)\left(9.8\ \frac{\text{m}}{\text{s}^2}\right)(30\text{ m})\ = 294{,}000\text{ Pa}\ = 294\text{ kPa}$$

Therefore, $P_w + P_m = 294\text{ kPa} + 7\text{ kPa}$, which is less than the annular pressure of ~2200 kPa caused by leaking natural gas at depth in this poorly completed borehole. The gas, therefore, easily penetrates the matrix of the Berea Sandstone as well as the fractures.

Return to Exercise 3
Return to where text linked to Exercise 3

Solution Exercise 4

1. Check the Bradenhead or Surface Casing Vent gauges to determine if there is elevated pressure in the well annulus. If there is, there is a driving force for fluid migration.
2. Using a map of the surficial deposits in the area, determine the likelihood of gas migrating through a permeable zone (e.g., silt or sand) beneath a low-permeability soil cover (clay or clayey silt). Confirm by augering shallow holes, watching for gas emissions.
3. Check the well log to determine if there are sub-vertical features, as in Figure 11 , that might daylight some distance from the well. Check these locations for gas concentration.
4. Check surrounding water supply wells for unusual behavior such as gas presence that could be linked to subsurface gas migration.
5. Check visually for distressed vegetation locally around the legacy well where gas migration may have locally desaturated the shallow sediments.
6. After a soaking rain, when the ground is well-saturated, explore visually for evidence of gas bubbling to surface, especially in low areas near the legacy wellbore.
7. Determine if there are other legacy wells or abandoned wells in the region and examine them for signs of gas migration.
8. If more precise measures are needed such as gas pressure or gas migration quantity, consider instrumenting boreholes for fluid sampling and accurate pressure measurements including surface gas collector rings, and collecting samples for geochemical analysis of gas and groundwater.

Return to Exercise 4↥

Return to where text linked to Exercise 4↥

12 List of Acronyms and Terms

AOG	Abandoned Oil and Gas Wells (AOG wells include exploration boreholes and unplugged wells)
amsl	above mean sea level, elevation
BFW	Base of Fresh Water. Kang and Jackson (2016) contain a summary of this depth for various USA states. In California, USA, it is set by the depth at which TDS < 3,000 ppm.
bgs	below ground surface
BGWP	Base of Ground Water Protection—the lowest occurrence of useable water, defined consistently by an accepted standard (e.g., 4,000 parts per million total dissolved solids in Alberta)
Brackish water	Water having total dissolved solids in the range 1,000 to 20,000 mg/L
Bradenhead	A type of casing head widely used in the US
Brine	A dense aqueous solution with > 35,000 mg/L in total dissolved solids
Fm.	Formation (in the formal stratigraphic sense)
FW	Fresh Water (typically defined to be < 1000 mg/L total dissolved solids)
GHGI	Green House Gas Inventory
GM	Gas Migration outside any wellbore casing resulting in surface discharge of fugitive gas
GWQ	Groundwater Quality
HF	Hydraulic Fracturing
MSHF	Multi-Stage Hydraulic Fracturing
MW	Monitoring Well
P&A	Plugged and Abandoned (definition varies with jurisdiction)
ppb	parts per billion, in fresh groundwater this is equivalent to μg/L
ppm	parts per million, in fresh groundwater this is equivalent to mg/L
SCVF	Surface Casing Vent Flow
SW	Salt Water (Saline water has TDS > 20,000 mg/L; sea water has TDS ~ 35,000 mg/L)
TDS	Total Dissolved Solids (in mg/L)
USGS	United States Geological Survey

13 Glossary

Annulus	The space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow. The pipe may consist of drill collars, drill pipe, casing, or tubing.
Bed	A layer of sediment, sedimentary rock, or stratum.
Bedding plane	A nearly flat surface representing a contact between two different sedimentary beds during a time of change. Each bedding plane marks the end of one deposit and the beginning of another having different characteristics.
Bradenhead valve	A valve to prevent the venting of methane into the atmosphere. This valve allows gas to build and increase the pressure above the fluid in the annulus.
Bridge plug	A mechanical plug that is installed in an open hole that provides a solid seal to isolate the lower part of the wellbore. Bridge plugs may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone.
Caliper probe	A mechanical device used to measure the internal diameter of a borehole or casing within a borehole.
Caliper log	A representation of the measured diameter of a borehole along its depth.
Casing	Large-diameter pipe lowered into an open drillhole and cemented in place.
Casing shoe	This is explained under the definition for shoe
Casing string	An assembled length of steel pipe that is configured to suit a specific wellbore. The sections of the pipe are connected and lowered into a wellbore, then cemented in place.
Casing thread	The threadform is found on casing joints. In addition to providing mechanical or structural strength, the casing thread must be compatible with the pressures and fluids associated with the application.

Cementing	Preparing and pumping cement into place in a wellbore. Cementing operations may be undertaken to seal the annulus after a casing string has been run, to seal a lost circulation zone, to set a plug in an existing well from which to push off with directional tools, or to plug a well so that it may be abandoned.
Centralizer	A device fitted with a hinged collar and bowsprings to keep the casing or liner in the center of the wellbore to help ensure efficient placement of a cement sheath around the casing string.
Coalbed methane recovery	Natural gas, predominantly methane [CH_4], that is recovered from coal formations, usually by using stimulation.
Conductor pipe	Casing string that is usually put into onshore wells first to prevent the sides of the hole from caving into the wellbore. Also called the drive pipe, this short pipe is driven into the ground. Conductor pipe is run because the shallow sections of most wells are drilled in unconsolidated sediment or soil.
Conventional oil and gas reservoir	Oil and gas that occur below a sealing caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores. Stimulation techniques are not required to recover conventional oil and gas.
Cross-linking agents	Chemicals that enhance the viscosity effect of the gel which is added to drilling fluid to increase its viscosity. Typically metallic salts are mixed with a base-gel fluid, such as a guar-gel system, to create a viscous gel used in some stimulation or pipeline cleaning treatments.
Drainage radius	The reservoir area or volume drained by the well.
Drilling mud	The fluid circulated through the drill string and wellbore during rotary drilling to cool and lubricate the drill bit and carry rock cuttings and fine particles out of the hole. Drilling mud may be water-based (including brine), oil-based, or synthetic oil-based. Additives may include materials such as bentonite clay or barite ($BaSO_4$) in a slurry, hence the name mud.
Fracking fluid	An abbreviation for fracturing fluid, a fluid injected into a well as part of a stimulation operation.

Fracking	A stimulation treatment routinely performed on oil and gas wells in the target zone of low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open.
Gas migration	A flow of gas that is detectable at ground surface outside of the outermost casing string (Forde et al., 2019c).
Inner string cementing	Introduction of cement slurry through the drill string inito the casing shoe.
Intermediate casing	A casing string that is generally set in place after the surface casing and before the production casing. The intermediate casing string protects against caving of weak or abnormally pressured formations and enables the use of drilling fluids of different densities necessary for the control of lower formations.
Intermediate zone	The zone occurring below exploited potable groundwater aquifers and deeper oil and gas reservoirs (Perra et al., 2022).
Jurisdiction	States, provinces, or nations in the USA and Canada.
Microannulus	Millimeter or sub-millimeter-sized channels that permit gas flow in the annulus behind the casing
Multi-stage hydraulic fracturing (MSHF)	The direct creation of fissures throughout several sections of a well through spaced perforation. Multi-use compacted "cushions", i.e., packers are used. The cushions expand under pressure to isolate those areas in which fracking has been completed.
Neat cement	A mixture of Portland cement powder and water, in which the ratio is carefully controlled.
Offset well	An existing oil and gas production well that is located close to a proposed well and that provides information for planning the proposed well.
Packer	A device that can be run into a wellbore with a smaller initial outside diameter that then expands to seal the wellbore. Packers employ flexible, elastomeric elements that expand.
Pay zone	The target hydrocarbon formation
Perforation	The breaching or perforation of the steel casing and cement to access the formation using downhole explosives to allow the injection of cement to plug a void in the cement sheath, as in 'plug and perf'.

Petroleum trap	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock type changes, such as unconformities, pinch-outs, and reefs).
Play	A regional set of discovered or possible oil and gas accumulations that exhibit similar geological characteristics, such as the Marcellus Shale play in Pennsylvania, Ohio, New York, of the USA, and some adjacent areas. A play involves a set of energy development operations in which seismic exploration work is undertaken and wells are drilled into a particular formation in a particular region, usually (but not always) leading to commercial development at some scale. Curtis (2002) provided an overview of what would become the major USA shale gas plays including their petrophysical properties
Primary cementing	The process of cementing the wellbore annulus to prevent cross-formational migration of gas and other fluids outside the casing.
Production	The phase that occurs after successful exploration and development and during which hydrocarbons are drained from an oil or gas field.
Production tubing	A non-cemented string of tubing through which oil or gas is produced. It is hung within the production casing. Production tubing is assembled with other completion components to make up the production string.
Production casing	A casing string that is set across the reservoir interval and within which the primary completion components are installed.
Production string	The primary conduit through which reservoir fluids are produced to the surface. The production string is typically assembled with tubing and completion components in a configuration that suits the wellbore conditions and the production method.
Proppant	Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used.

Setback	A setback is a minimum distance that must be maintained between an oil and gas facility (e.g., well, pipeline, gas plant) and a dwelling, rural housing development, urban center, or public facility. Setbacks vary according to the type of development and whether the well, facility, or pipeline contains sour gas.
Scratcher	A device for cleaning mud and mud filter cake off of the wellbore wall when cementing casing in the hole to ensure good contact and bonding between the cement and the wellbore wall.
Shale oil and gas recovery	Recovery of oil and gas from mature oil shales.
Shoe (or casing shoe)	The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string.
Slickwater fracking	Insertion of a combination of water, chemicals, and sand into a crude oil or natural gas well to reduce friction pressure and create a fracture.
Spacer fluid	Any liquid used to physically separate one special-purpose liquid from another. Special-purpose liquids are typically prone to contamination, so a spacer fluid compatible with each is used between the two. The most common spacer fluid is water. However, chemicals are usually added to enhance its performance for the particular operation. Spacers are used primarily when changing mud types and to separate mud from cement during cementing operations. In the former, an oil-base fluid must be kept separate from a water-base fluid. In this case, the spacer may be a base oil. In the latter operation, a chemically treated water spacer usually separates drilling mud from cement slurry.
Strong rock	Rock with sufficient compressive strength to withstand an imposed stress without failure. An unconfined compressive strength of > 50-MPa or a triaxial strength of >30 MPa indicates a strong sedimentary rock.

Surface casing	A large-diameter, relatively low-pressure pipe string set in shallow yet competent formations for several reasons. First, the surface casing protects fresh-water aquifers. Second, the surface casing provides minimal pressure integrity and thus enables a diverter or perhaps even a blowout preventer (BOP) to be attached to the top of the surface casing string after it is successfully cemented in place. Third, the surface casing provides structural strength so that the remaining casing strings may be suspended at the top and inside of the surface casing.
Surface casing vent	An outlet at the upper terminal of a well casing which provides atmospheric pressure in the well and allows the escape of gases when present.
Suspended well	An oil and gas production well that has been temporarily isolated from the producing reservoir. Also called an 'idle' well.
Swab cup	A rubber or rubberlike device used on a swab mandrel that forms a seal between the swab and the wall of the tubing or casing.
Target reservoir formation	The geologic gas or oil formation from which oil and gas are to be produced.
Unconventional oil and gas recovery	Oil and natural gas that is produced by means that do not meet the criteria for conventional production. It refers to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs, and tight gas sands are considered unconventional resources.
Well abandonment	To prepare a well to be closed permanently, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir.
Wiper plug	Another term for cementing plug, it is a rubber plug used to separate the cement slurry from other fluids, reducing contamination and maintaining predictable slurry performance. Two types of cementing plug are typically used in a cementing operation.

The bottom plug is launched ahead of the cement slurry to minimize contamination by fluids inside the casing before cementing.

The top plug has a solid body that provides a positive indication of contact with the landing collar and bottom plug through an increase in pump pressure.

14 About the Authors

Richard Jackson was a research hydrogeologist with Environment Canada from 1975 to 1989, when he joined INTERA in Texas. There his group developed enhanced oil recovery methods to remove solvents and hydrocarbons from aquifers. He returned to Canada in 2006 as a Principal with INTERA, now Geofirma Engineering Ltd. of Ottawa, and worked as a task leader on nuclear-waste disposal site characterization. He retired from Geofirma in 2017, became a Geofirma Fellow but continues working on geological CO_2 storage.

He is now an Adjunct Professor at the University of Waterloo and works on issues of geological CO_2 storage. His textbook, *Earth Science for Civil & Environmental Engineers*, was published by Cambridge University Press in 2019. In 2023 he completed a Road Map on R&D for geological CO_2 storage in Southern Ontario for Natural Resources Canada.

He received the 2013 Farvolden Award from the Canadian National Chapter of the International Association of Hydrogeologists and the 2008 Geoenvironmental Award from the Canadian Geotechnical Society.

Robert Walsh is a Principal Engineer with Geofirma Engineering, specializing in computational modeling of geosphere processes. He studied civil engineering at the University of Alberta and continued with graduate studies in Germany, where he studied thermo-, hydro-, mechanical coupling in fractured rock, and he developed new methods to model these processes. He returned to Canada in 2007. Much of his work at that time focused the solving the problem of safe disposal of radioactive waste with an emphasis on the subsurface transport of soluble radionuclides, and the production and transport of gases in a waste repository setting.

He leads a multi-year effort to model the effect of increasing maximum operating pressure for gas storage in depleted natural gas reservoirs. He was instrumental in developing a technology roadmap to address wellbore leakage and was the lead modeler for a scoping tool to identify and characterize pathways for methane emission from legacy natural gas and oil wells. Recently, much of his work has focused on geological characterization and modeling for carbon sequestration projects.

Mary Kang's main research areas are groundwater hydrology and environmental impacts of subsurface-based energy development. Application areas include groundwater impacts and greenhouse gas emissions related to oil and gas development and geologic storage of carbon dioxide. Her projects involve the development of multi-phase flow through porous media, field measurements of gas fluxes, and geospatial and statistical data analysis. Fluids of interest include carbon dioxide, methane and other hydrocarbons, and water.

Maurice Dusseault is a Geological Engineering Professor at the University of Waterloo where he has been since 1982. His major research activities are focused on subsurface energy issues including the use of salt caverns or steel-cased wellbores for compressed air energy storage; seasonal heat storage in impermeable rock masses with borehole heat exchanger arrays; legacy wellbore gas leakage issues; development of geothermal energy for heat and power in northern climates; geomechanics of geothermal well development and operation; and CO_2 sequestration geomechanics including deep biosolids injection.

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