Factors Influencing the Occurrence of Energy Wellbore Leakage in Alberta

by

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ABSTRACT

Wellbore leakage refers to the unwanted leakage of subsurface fluids along the annuli of oil and gas wellbores. Wellbore leakage is of concern because it may cause natural gas − and exceptionally other fluids such as brine, hydraulic fracturing fluids, or other gases − to enter a shallow aquifer, thereby deteriorating the water quality, or be emitted directly to the atmosphere as a greenhouse gas. Wellbore leakage is also considered to be a first-order risk issue for CO_2 sequestration projects and hydraulic fracture stimulation (particularly interaction with offset wells during stimulation).

Watson and Bachu (2009) identified major impact factors on the occurrence of wellbore leakage for wellbores spud up until 2004 and established the basis for our current understanding of wellbore leakage development. However, there is uncertainty as to whether their findings are applicable to more recently completed wellbores because drilling practices and wellbore orientation are changing rapidly. The purpose of this research has been to evaluate the influence of well design (i.e., orientation), well type (i.e., produced hydrocarbon), drilling contractor and reported drilling issues on the development of wellbore leakage among wellbores drilled over the past decade (2004-2013) in Alberta.

Consistent with past research, well design was found to have an influence on the development of wellbore leakage regardless of other factors (i.e., well type, drilling contractor or reported drilling issues). Specifically, non-vertical wellbores were generally more prone to leakage problems than vertical wellbores. The development of leakage problems within a particular well design was variable, depending on well type, drilling contractor and reported drilling issues. Construction challenges, e.g., cementing, might explain why non-vertical wellbores were more prone to leakage problems than vertical wellbores, but cannot explain why some non-vertical wellbores were more prone to leakage problems than other non-vertical wellbores.

In contrast to previous research, a difference in the occurrence of leakage problems was found among wellbores producing different hydrocarbons. This finding was reasonably anticipated because some wellbores may be exposed to higher levels of operational stresses depending on the required production activities, e.g., steam-assisted gravity drainage. Furthermore, the occurrence of leakage problems among each well type appeared to be closely related to well design. This indicates that well design might also have an influence on the development of

leakage problems among different well types.

A statistically significant difference in the development of leakage problems was found between wellbores drilled by particular contractors. This finding might be attributed to best practice principles implemented by the various companies. Alternatively, the observed differences might be an artifact of varying standards for monitoring and reporting leakage problems between companies.

Wellbores with, rather than without, reported drilling issues were found to have the lowest average occurrence rate of leakage problems. This finding was not expected, because it was hypothesized that wellbores with reported drilling issues would encounter challenges that would subsequently jeopardize the integrity of the wellbore. We speculate that this finding is the result of successful risk management of drilling issues by industry as to prevent further issues from being encountered (i.e., problems triggered more attention, leading to more care and better outcomes).

Overall, this study indicated that there are occurrences of leakage problems that prove to be statistically significant in relation to well design, well type, drilling contractor and reported drilling issues. This study raises questions regarding our understanding of the mechanisms responsible for the development of leakage problems. Industry and regulators might focus future research and quality assurance on problematic wellbores identified in this research.

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1 INTRODUCTION

1.1 Background

Oil and gas resources are an important component of the Canadian economy. In 2010, most energy consumed in Canada corresponded to refined petroleum products (41%) and natural gas (31%), which was used in many sectors including transportation, residential, agriculture, manufacturing, commercial and public administration, mining, and oil and gas extraction (Statistics Canada, 2012). Oil and gas production also contributes to the Canadian economy through exports to foreign markets. According to Statistics Canada (2012), Canada exported 63% of crude oil, 61% of marketable natural gas, and 20% of its refined petroleum products in 2010. Recent expansion in the development of unconventional resources, such as coalbed methane, tight gas and shale gas, further provide Canada with the opportunity to become a global supplier in natural gas markets through overseas exports of liquefied natural gas (Natural Resources Canada, 2013; National Energy Board, 2013, 2014). Technological advances over the past 50 years, including hydraulic fracturing and horizontal drilling, have enabled industry to expand production rapidly in many regions, including bringing oil and gas development into areas that have historically seen minimal amounts of activity (Speight, 2013).

Regardless of the value of oil and gas as an energy resource, its production continues to raise environmental concerns. Over the past decade, with the expansion of shale gas development, hydraulic fracturing has been at the forefront of concern and has been criticized for presenting unwarranted risks to shallow potable groundwater resources. Osborn et al. (2011), for example, found that methane concentrations in drinking-water wells increased with proximity to the nearest gas wells. The isotopic signatures and bulk chemical composition of the gases led the authors to conclude that the gases were thermogenic in origin, and must have migrated from deeper formations within the subsurface. The mechanism responsible for the fluid migration into the shallow drinking-water aquifers was poorly understood and consequently the authors could not rule out the influence of hydraulic fracturing as a possible mechanism. However, there is increasing evidence that the real concerns are related to wellbore leakage (Darrah et al., 2014; Dusseault and Jackson, 2014; Jackson, 2014).

Gas migration (GM) and surface casing vent flow (SCVF), collectively referred to as wellbore leakage, refer to the unwanted seepage of subsurface fluids (e.g., liquid and gaseous hydrocarbons) along energy (i.e., oil and gas) wellbores. Specifically, GM refers to fluid seepage along a pathway outside the outermost casing string and a SCVF describes seepage along a pathway between the surface casing and the next innermost casing string. Wellbore leakage is the consequence of a well integrity problem, whereby the steel casings and protective cement sheath fail to provide an effective barrier to migrating fluids (King and King, 2013).

The possibility of subsurface fluid migration to the surface has raised environmental concerns. Leaky wellbores, as well as other upstream oil and gas sources such as pipelines and storage tanks, are responsible for the emission of methane to the atmosphere. This is of particular concern because methane is a very strong greenhouse gas and is approximately 84-times stronger than carbon dioxide on a 20-year timescale according to the Intergovernmental Panel on Climate Change's most recent assessment (Myhre et al., 2013). This can be problematic because studies (e.g., Alvarez et al., 2012) suggest that significant methane emissions from upstream oil and gas activities can potentially offset any advantages (i.e., reduced carbon footprint) that might accompany using natural gas instead of other fossil fuels.

Wellbore leakage can also negatively impact shallow potable[1] groundwater supplies by providing a conduit for methane to the shallow subsurface. Methane itself is generally not considered a groundwater contaminant because it is non-toxic and is both colourless and odourless. In fact, methane is ubiquitous in the majority of groundwater systems due to: a) in situ production by microbial-mediated processes (Schoell, 1980; Barker and Fritz, 1981; Whiticar, 1999; Ortiz-Llorente and Alvarez-Cobelas, 2012); and b) natural leakage of abiotic methane from deeper basins (Schoell, 1980; Barker and Fritz, 1981; Révész et al., 2012; Molofsky et al., 2013). However, methane, like any other hydrocarbon, undergoes microbial-mediated redox reactions, whereby methane is oxidized to carbon dioxide while a terminal electron acceptor present in the aquifer system (e.g., oxygen, nitrate, manganese, iron or sulphate) is reduced (Baedecker et al., 1993; National Research Council, 2000; van Stempvoort et al., 2005). These reduced species, or "byproducts", often linger in groundwater systems following redox processes and have the potential to render water supplies unpalatable (Kelly et al., 1985; Baedecker et al., 1993; National Research Council, 2000; van Stempvoort et al., 2005). An increase in methane

[1] A potable aquifer is defined here as any groundwater resource with a total dissolved solid concentration less than 4000 mg/l, that is suitable for domestic and industrial use (Alberta Energy Regulator, 2003)

levels in groundwater systems may consequently elevate the concentration of these byproducts, thereby resulting in well water discoloration, particulate suspension, mineral precipitation, and the development of foul (e.g., sulphur) odours (Kelly et al., 1985; Gorody, 2012).

Wellbore leakage can impact operations that depend on oil and gas wellbores, such as carbon dioxide sequestration and hydraulic fracturing operations. In both cases, poorly sealed offset wellbores may provide a conduit for fluids (e.g., injected and displaced formation fluids) to the surface. For carbon dioxide sequestration operations, poorly sealed offset energy wellbores may allow for carbon dioxide to leak to the surface, because such operations often utilize depleted oil and gas reservoirs that may be directly penetrated by leaky wellbores (Watson and Bachu, 2009). Likewise, offset legacy wellbores with integrity problems may allow seepage of hydraulic fracturing fluids to the shallow subsurface (Dusseault and Jackson, 2014). As discussed by the authors, this may occur by either the: a) intersection of a hydraulically induced fracture with an offset wellbore; or b) penetration of an offset wellbore with the stimulated rock volume. Therefore, wellbore integrity is needed to ensure operations proceed uninhibited. Given the risks of wellbore leakage, it is necessary to understand the factors that contribute to well integrity problems.

1.2 Purpose

The purpose of this research is to investigate the influence of several factors on the occurrence of energy wellbore leakage development. The focus of this study is on wellbores drilled within the province of Alberta, Canada. This Province was selected because: a) it has a long history of oil and gas development; and b) the Province has a rich database of wellbore leakage information that has been made readily accessible for analysis.

1.3 Site Background

Alberta is located in Western Canada within the Western Canadian Sedimentary Basin (WCSB). The Province describes itself as "Canada's energy province" (Alberta Government, 2015), given a diverse and abundant supply of resources including natural gas, conventional oil, coal, minerals and the oil sands. Established reserves include 167 billion barrels of bitumen and crude oil, 34 trillion cubic feet of natural gas, and 37 billion tons of coal (Alberta Government, 2015).

The oil and gas industry in Alberta is regulated by the Alberta Energy Regulator (AER), formerly the Energy Resources Conservation Board (ERCB). The purpose of the AER is to "ensure safe, efficient, orderly and environmentally responsible development of hydrocarbons over their entire life cycle" (Alberta Energy Regulator, 2015). They are the sole regulator of energy resources, with responsibilities from application and exploration, construction and development, abandonment, reclamation and remediation. This includes regulation of both the resources that are produced and the infrastructure (e.g., pipelines, operating wells, oil and gas facilities, thermal oil sands projects, oil sands mines, coal mines, and coal processing plants) used for producing and processing the resources (Alberta Energy Regulator, 2015).

Regulations outlined by the AER are in place to ensure that the *Environmental Protection and Enhancement Act* (EPEA), the *Water Act*, and the *Public Lands Act and the Mines and Minerals Act* are upheld. The AER has authority to ensure that industry is complying with regulations by regular inspections to ensure that all applicable requirements are met (Alberta Energy Regulator, 2015). If violations are found, the AER may penalize companies with various enforcement tools including: i) more frequent and detailed inspections; ii) more stringent planning requirements; iii) enforcement orders; iv) shutting down operations; v) levying administrative penalties; and vi) prosecution.

1.4 Overview of Thesis

The purpose of Chapter 2 is to review the pertinent literature, including what is currently required of the oil and gas industry in regards to wellbore construction and design criteria, wellbore leakage monitoring, and also leakage remediation. The latter half of this Chapter outlines what is currently known about wellbore leakage, including a detailed discussion of the principal mechanisms of wellbore leakage development and an introduction to a previous study by Watson and Bachu (2009) that identified major impact factors on wellbore leakage development.

An overview of the methodology of this research is provided in Chapter 3, including the study design, the source of the data, data exclusions and the analysis approach. The factors to be analyzed are also identified.

Chapter 4 presents the results of the study. For each study factor, an overview of drilling activity, a summary of reported leakage problems and the results of statistical tests are presented.

Chapter 5 discusses the results of the study and possible implications of the findings. This Chapter also presents a discussion of possible limitations and provides recommendations for policy and research relevant to industry, government and researchers.

It is anticipated that this research will improve understanding of the persistence of wellbore leakage in Alberta so that industry and regulators can make more informed decisions regarding leakage mitigation.

2 LITERATURE REVIEW

2.1 Wellbore Drilling, Casing and Cementing

The construction of an energy wellbore generally begins with the installation of a 6 to 12 m depth conductor casing, which serves to prevent the collapse of unconsolidated or cohesionless soil and rock into the borehole. In Alberta, a conductor casing is required to be installed if there are known hydrocarbon formations located above the surface casing setting depth or if the surface casing is set at a depth greater than 650 m. If the conductor casing is required for well control, the AER requires that the casing be set between 20 and 30 m into a competent formation, and in all cases, the conductor casing must be cemented full length to the surface using cement that meets minimum quality specifications (Alberta Energy Regulator, 1990, 2013).

Following the installation of a conductor casing, a drill string comprised of the drill bit, the mud motor, drill collars, stabilizers and reamers (collectively referred to as the bottomhole assembly) is guided into the conductor casing, and advanced into the subsurface through rotation. The date drilling commences is referred to as the spud date of a wellbore. As drilling proceeds, drilling fluid, generally a clay-water mixture and other additives, is circulated down the drill string and up through the annulus around the pipe to clean drill cuttings from the hole, lubricate and cool the drill bit, reduce the friction between the drill string and formation wall, maintain wellbore stability and prevent fluids held within adjacent permeable formations from entering the borehole (Caenn et al., 2011; Varhaug, 2011). For the protection of the shallow subsurface, non-toxic drilling fluid is used until all porous formations are isolated by cement (Alberta Energy Regulator, 1990). Wellbores are drilled in one of three orientations: deviated (including slant wells), vertical or horizontal. A deviated wellbore is defined as any wellbore where the total length is greater than the true vertical depth (TVD). A vertical wellbore is any wellbore where the total depth is equal to the TVD. Horizontal wellbores are those initially drilled vertically, deviating within the last few hundred meters of the target formation, and followed by horizontal drilling along the target formation. The orientation of the wellbore is referred to as "well design" throughout this paper.

As a borehole deepens, strong and continuous steel casing strings are run through the borehole in a concentric manner and subsequently cemented in place. Generally, there are three main types of casing strings installed, referred to as the surface, intermediate and production casings. Each casing string serves a specific purpose, although collectively the casing strings provide a multiple barrier system, which prevents behind the casing communication of subsurface fluids, or what is more commonly referred to as providing zonal isolation (King and King, 2013).

The surface casing string is placed first, serving to provide wellbore control and also permanently isolate the shallow subsurface, particularly potable aquifers, from drilling and formation fluids. The surface casing is run to a predetermined minimum depth, which is a reflection of the depth of the base of groundwater protection (BGWP; i.e., the depth of the base of the deepest potable aquifer) and local geology. In Alberta, the setting depth is generally determined using a form – the Surface Casing Depth Calculation Form – with the exception of wellbores located in specified areas (e.g., Senex), or wellbores constructed for enhanced recovery operations, i.e., thermal wells, for which there are other regulations (Alberta Energy Regulator, 2013).

Once the surface casing has been installed, the casing is then cemented in place by circulating a cement slurry – generally a water-based Portland Class G cement slurry with a density of approximately 2.0 Mg/m^3 or slightly higher (Dusseault et al., 2000) – down the casing and back up through the annular region between the formation rock and the steel casing (Figure 2.1). The surface casing must be cemented full length in all circumstances. The cement, once set, is intended to provide a continuous impermeable barrier to formation fluids. To prevent the possibility of pressure build up, the surface casing is left open to vent freely to the atmosphere (Alberta Energy Regulator, 1990).

Deeper drilling proceeds once the surface casing has been successfully installed and the cement placed in the annular region has reached sufficient compressive strength. The next step generally includes the installation of a series of intermediate casing strings to provide protection against pressure abnormalities and weak formations so that drilling can proceed unimpeded.

The cementing requirements for the intermediate casing string are largely dependent on the configuration of the surface casing and well locality. The AER requires that the next innermost casing string from the surface casing be cemented full length if the surface casing is either less than 180 m depth or 25 m below any potable aquifer (Alberta Energy Regulator, 1990). Therefore, for wellbores where an intermediate casing string is installed and the surface casing

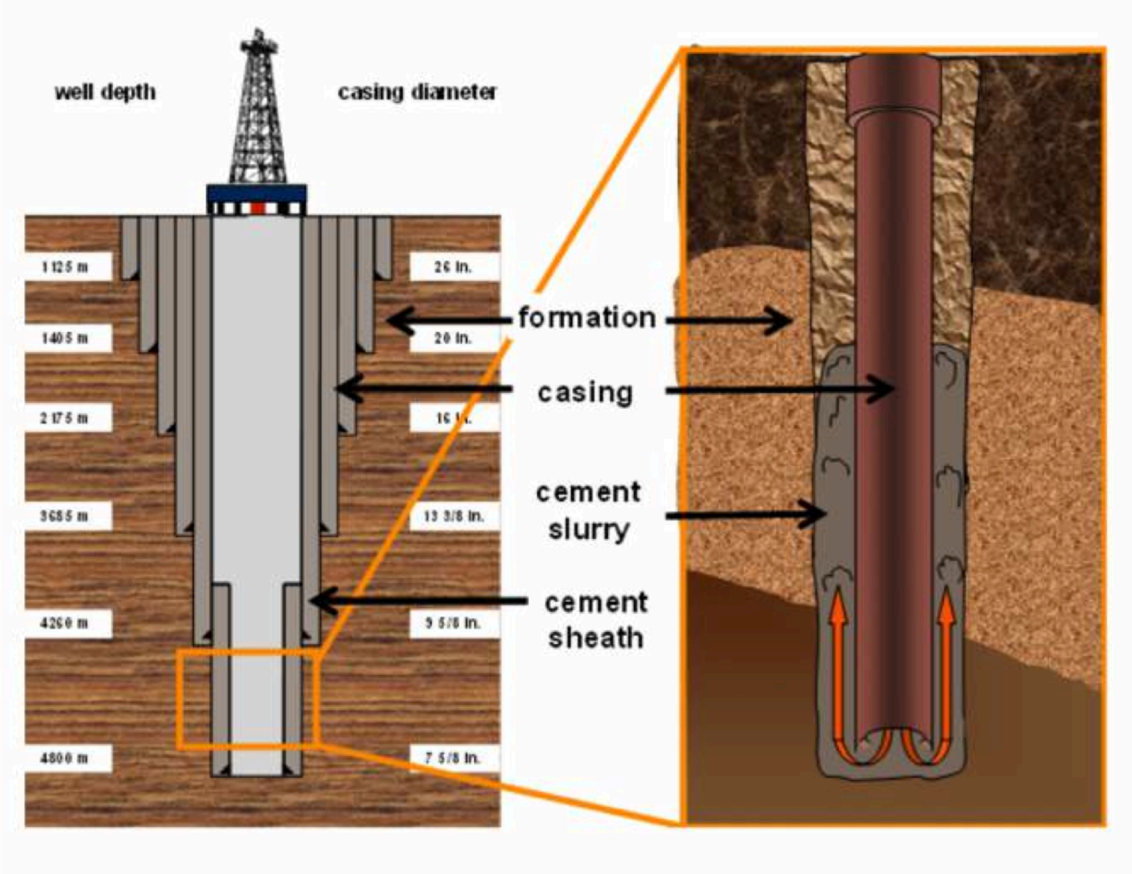

Figure 2.1. Schematic of a primary cementing operation (from Powerflex Cementers, Inc.)

meets the aforementioned criteria, the intermediate casing must be cemented full length. In all other cases, the intermediate casing cement top is dependent on the location of the wellbore. The AER has prescribed required cement tops for wellbores depending on the local geology of the area. These cement tops are outlined by township, range and meridian in Directive 009 (Alberta Energy Regulator, 1990).

The final casing string installed is the production casing. The production casing is run from the surface to total depth, and contains the components for completion and production, including the production tubing and other bits of downhole equipment referred to as jewelry (Varhaug, 2011). The cementing requirements for the production casing follow the same requirements for the intermediate casing. The production casing is therefore only required to be cemented full length if there is no intermediate casing string installed, and the surface casing is either less than 180 m depth, or 25 m below any potable aquifer.

Many newer unconventional wellbores targeting shale gas (or shale oil) are drilled vertically or at an angle of inclination ($\sim$10-80^{o}), but deviate within the last few hundred meters before

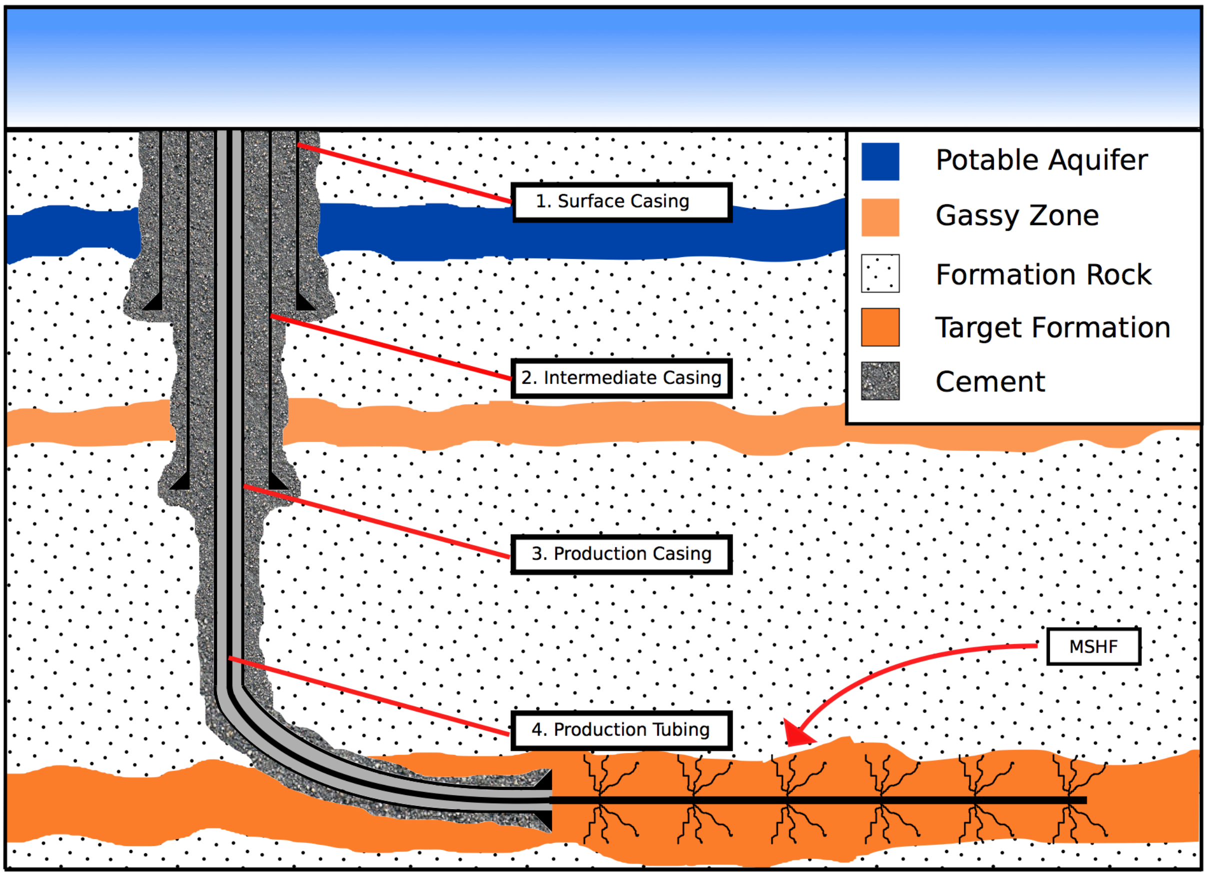

Figure 2.2. Structure of a horizontal, unconventional energy wellbore where all casing strings are cemented full length.

the target formation is reached and then drilled horizontally along the target formation (Figure 2.2). Drilling then proceeds through the production casing along a horizontal plane for up to several kilometers. The horizontal section is subsequently: a) cemented full length and then perforated and fractured in multiple stages using plugs, or b) equipped with special equipment and hardware used for multistage hydraulic fracturing (MSHF) that is anchored in place using several swelling packers (rather than cement) and tied into the production casing.

2.2 Wellbore Integrity and Wellbore Leakage

Wellbores are designed in a manner to provide zonal isolation such that there is no interzonal communication of subsurface fluids (see Section 2.1). However, in order for a wellbore to provide zonal isolation, the barriers of a wellbore must first be constructed properly and maintained through the life of the well. The integrity of a wellbore is dependent on all components of a barrier, including the casing and cement, valves, and pressure-rated housings. If one or more of these components fail, leakage may develop (King and King, 2013).

Although the failure of a barrier may result in leakage development, as pointed out by King and King (2013), the benefit of constructing a wellbore with a multiple barrier system is that the failure of a single barrier does not necessarily result in pollution. Having redundant barriers ensures that if one barrier were to fail, another barrier would be present to interrupt any flow that may develop. Only in the case of well integrity failure, described by King and King (2013) as "...the undesirable result in which all barriers in a potential leak path fail in such a way that a leak path is created", may fluid leakage result in pollution.

Gas migration (GM) and surface casing vent flow (SCVF) indicate failure in well integrity, where the cement sheath was not adequately placed, or the cement seal was not maintained through the life of the well (Dusseault et al., 2000; Watson and Bachu, 2009; King and King, 2013; Dusseault and Jackson, 2014). GM, as illustrated on the left in Figure 2.3, occurs as seepage through a microannular channel − a small gap on the order of micrometers − located either between the cement sheath and the borehole wall or between the cement sheath and surface casing string. Leakage may also occur through drilling damage to the borehole wall, such as washed-out areas and drilling induced micro fissures, into which cement was not adequately placed.

Alternatively, fluids may migrate between the surface casing and the next innermost casing string (either an intermediate or production casing string). Again, fluids may migrate through a microannular channel between the cement sheath and a casing string, or through discontinuities in the cement sheath, such as channels or fractures (on the order of millimeters to centimeters) or where no cement was placed at all (Figure 2.3). Fluid seepage through such pathways is commonly referred to as a SCVF, because fluid flow is detected at through the surface casing vent assembly (Alberta Energy Regulator, 2003). Generally, SCVF does not present a risk to the shallow subsurface because there is an additional steel casing and cement barrier between the flow path and the surrounding formations. In the U.S. where it is common practice to shut-in the surface casing vent, subsequent pressure build up around the surface casing shoe may result in lateral migration of subsurface fluids if fluid pressures exceed pore and capillary entry pressures (see Chafin, 1994; Penoyer, 2013). For this reason, common practice in Canada is to leave surface casing vents open to the atmosphere. Other forms of well integrity issues including poorly threaded casings and casing failures are beyond the scope of this research.

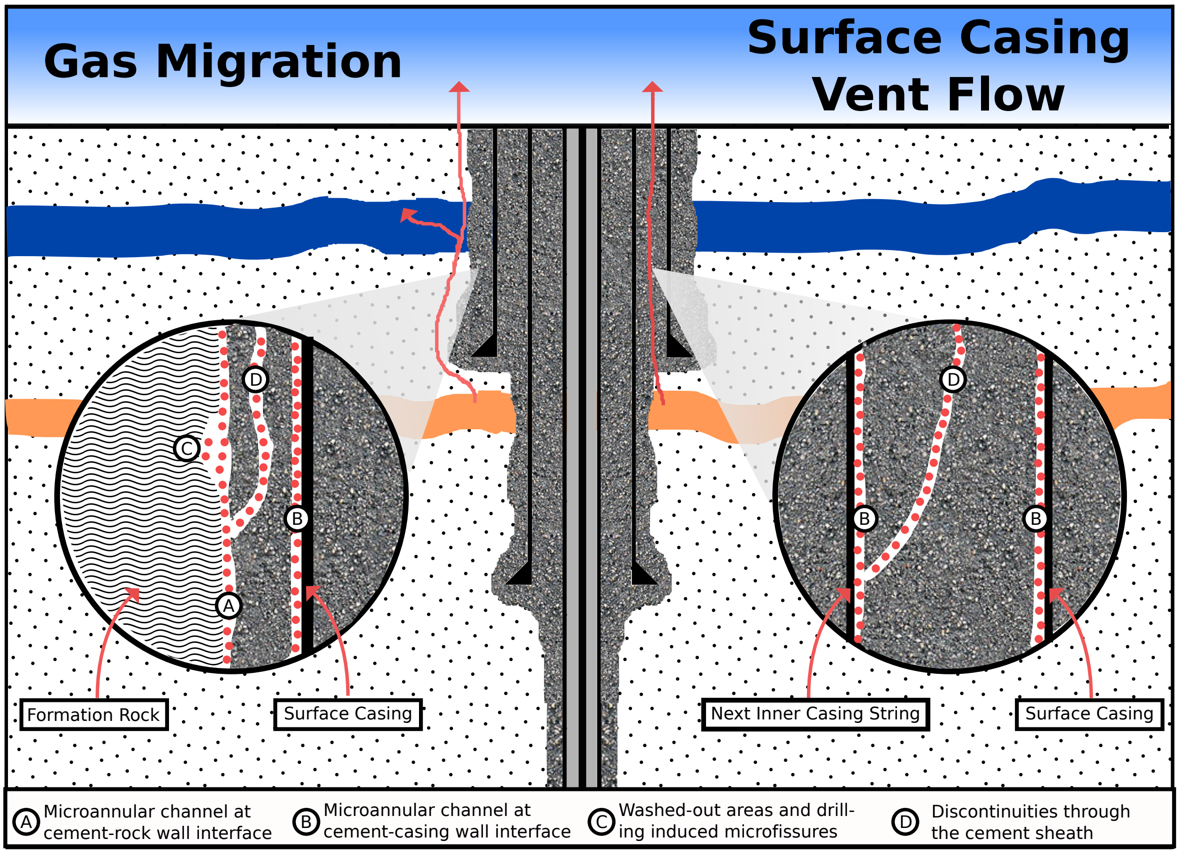

Figure 2.3. Possible wellbore leakage pathways as a consequence of flaws in the cement sheath. Fluid leakage through pathways outside the outermost casing string is referred to GM. Leakage through pathways between the surface casing and next innermost casing string is referred to as SCVF.

In addition to a continuous pathway, the development of a leakage problem further requires that there be a source of fluid and a sufficient driving force (Watson and Bachu, 2009). At a given site, there may be several potential fluid-bearing formations penetrated by a wellbore that may be the leakage source. Evidence suggests that the majority of leaks originate from a non-target formation, i.e., a formation that contains gas but in non-commercial quantities. This is based on the work of Muehlenbachs (2012, 2013), where the author found that among a subset of wellbores located in British Columbia, three-quarters of SCVF gas originated from a formation located above the target formation, i.e., an intermediate-depth source. Fluids (both liquids and gas) held within these intermediate depth zones can be reasonably assumed to exist at the same pressure. Since these formations are thin, they are uneconomical to produce and therefore the pressure remains unchanged. Methane and other buoyant gases held within these formations will readily migrate from these formations, given a continuous pathway (Dusseault and Jackson, 2014).

The target formation is much less commonly found to be the source of migrating fluids in energy wellbores. This is most likely attributed to the depletion of pressures in the target formation during production as well as superior cement quality near the bottom of the borehole (Watson, 2004; Dusseault and Jackson, 2014). Furthermore, since wellbores are constructed with a multiple barrier system, the likelihood of there being a continuous pathway from the target formation to the surface is low, given that this would require multiple barrier failures (King and King, 2013).

Wellbore leakage is inclusive of any subsurface fluid migrating uncontrollably to the surface, including gaseous and liquid hydrocarbons (e.g., crude bitumen and crude oil), water (both potable and non-potable) and other contaminants (e.g., condensates and wastes) (Alberta Energy Regulator, 2014). However, as discussed by Dusseault and Jackson (2014), generally only methane and other buoyant gases are found to be leaking because the density of formation liquids is often too high and also the target formation is depleted over time.

2.3 Wellbore Leakage and Other Leakage Pathways

Determining the origin of hydrocarbons in groundwater is not a simple task, because often there are multiple potential sources. In some cases, the mere presence of methane in groundwater may not be indicative of pollution, because methane is known to be generated naturally in groundwater systems through microbial-mediated processes, i.e., biogenic methane (Schoell, 1980; Barker and Fritz, 1981; Whiticar, 1999; Ortiz-Llorente and Alvarez-Cobelas, 2012). Methane is also produced abiotically by thermal decomposition of organic matter during burial and diagenesis of sediments, i.e., thermocatalytic methane (Schoell, 1980). The different types of methane carry distinctive geochemical and carbon-isotope signatures that can be used to discriminate between the origin (see Section 2.5.2).

Since thermocatalytic methane is generated at depth, its presence in shallow groundwater systems is indicative of leakage from the subsurface. However, natural seepage of methane from the subsurface has been documented (Barker, 1979), and therefore the presence of thermocatalytic methane in shallow groundwater systems does not necessarily indicate anthropogenic activities are responsible. Rather, there are several possible natural, i.e., pre-existing, and anthropogenically generated conduits. As depicted in Figure 2.4, pre-existing pathways may include natural fractures, faults, joints and bedding planes (1-2). Anthropogenically induced path-

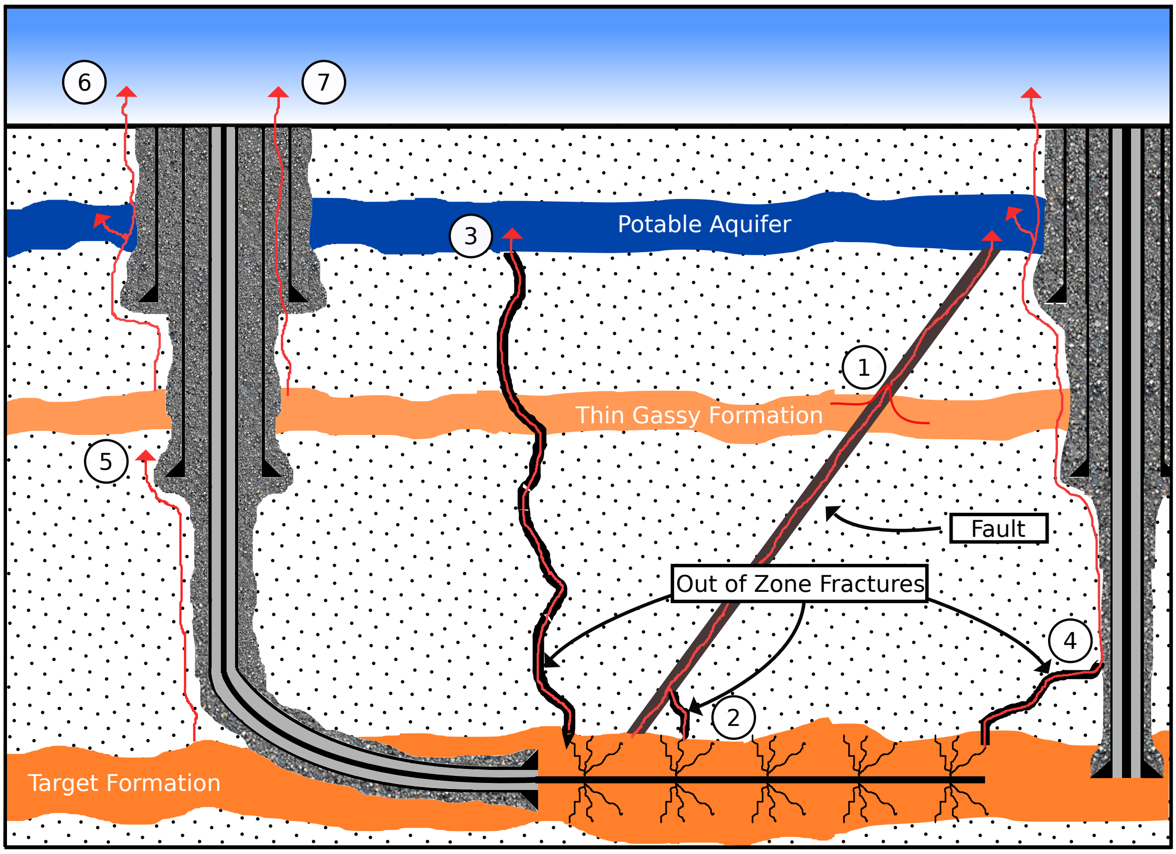

Figure 2.4. Possible subsurface fluid leakage pathways: (1-2) leakage through pre-existing pathways; (3) leakage through a hydraulically induced fracture; (4) leakage through an offset wellbore; and (5-7) leakage through an energy wellbore.

ways may include a hydraulically induced fracture (3) or a poorly sealed energy wellbore (4-7). When thermocatalytic methane is detected in shallow groundwater systems, perhaps one of the greatest challenges is identifying the pathway by which the methane migrated from the subsurface. This is particularly difficult in areas of oil and gas production where they may be several potential sources of hydrocarbons.

The risks attributed to each leakage pathway remain an active debate in literature. In particular, the influence of hydraulic fracturing on fluid migration, such as the possibility of a hydraulically induced fracture providing a conduit for subsurface fluids to the shallow subsurface (i.e., Figure 2.4, pathway 3), has received significant attention. For example, Myers (2012) examined the impacts of hydraulic fracturing on groundwater flow patterns in the Marcellus Shale. The author's results suggested that the hydrologic stress of hydraulic fracturing could allow fluids (fracturing fluids and formation fluids) to migrate vertically, reaching drinking water aquifers in a time period of under 10 years. However, these results have been questioned, because the study had a flawed conceptualization of the hydrogeology (Saiers and Barth, 2012) and critical limitations in the underlining assumptions used for the model (Cohen et al., 2013).

A recent article (Dusseault and Jackson, 2014) substantiated that subsurface fluid migration to the surface through a fully-penetrating hydraulically-induced pathway was most unlikely. There were several arguments made by the authors:

- Good cement seals near production zone:
  - The cement quality at the bottom part of the production casing where hydraulic fracturing takes places is of usually of highest quality. This means that there is usually a good seal, making it unlikely for fluids associated with hydraulic fracturing to migrate upwards.
- Hydraulic fracture growth limited:
  - Induced hydraulic fractures migrate preferentially in a direction perpendicular to the least principal stress, which, for deep horizontal wellbores, is oriented horizontally, so that induced fractures are vertical. Given that there is a greater upward driving force from fluid buoyancy, induced vertical fractures generally rise. However, the total height of fracture growth is generally well contained within the stimulated rock volume. This is attributed to the fact that stimulating fracture growth beyond the target formation would require significantly higher volumes of water and pumping times, for which there is no economic incentive for industry to do so.
  - Fracture growth is further constrained within about 600 m for onshore shales (Davies et al., 2012) as a consequence of fluid diversion (i.e., leak-off) in pre-existing pathways (e.g., joints, faults and bedding-plane partings).
- Principal stress directions change with depth:
  - While in deeper regions, the least principal stress is along the direction of the wellbore, in shallower regions, where there is less of an overburden, the least principal stress is in the vertical direction. Therefore, induced fractures will preferentially propagate in a horizontal direction before a freshwater aquifer is reached.
- Fluid is unlikely to migrate upwards following production:

- As the target formation is produced, the formation becomes depleted relative to surrounding formation pressures, i.e., a low-pressure zone, making it more likely for fluids to flow towards this zone, rather than away.
- Fluid is further held by strong capillary forces within shale formations and is therefore unlikely to migrate upwards.

Although the overall risks attributed to each leakage pathway are not fully understood, there is a growing consensus that poorly sealed energy wellbores present the greatest risks to the environment relative to other subsurface leakage pathways (Darrah et al., 2014; Dusseault and Jackson, 2014; Jackson, 2014). However, the source of the problem and the critical pathway are generally not immediately clear and often thorough field analyses are required to constrain the problem (see Section 2.5.2).

2.4 Wellbore Leakage Monitoring

2.4.1 Testing and Reporting Requirements

In Alberta, the Alberta Energy Regulator requires that newly constructed wellbores be tested for a SCVF within 90 days of drilling rig release, i.e., after construction and completion and before full production begins, and furthermore that wells be tested at final abandonment, which may be decades later (Alberta Energy Regulator, 2003). Any measurable fluid flow through the surface casing vent assembly is indicative of a wellbore leakage problem. Upon detection of fluid flow, industry is then required to classify the leak as either serious or non-serious. A serious vent flow is a fluid leak that meets any of the criteria outlined in Alberta Energy Regulator (2003). Serious vent flows include: leakage in the presence of an unprotected (i.e., uncemented) potable aquifer; stabilized gas flows exceeding a flow rate of 300 cubic meters daily; non-gaseous fluid flows such as hydrocarbon liquid (e.g., oil) or water (usable or saline); and vent flows with the presence of hydrogen sulphide (H_2S). The AER does not consider vent flows in the presence of an unprotected usable water resource to be serious if the fluid flow is comprised solely of gas and no other risks are presented to groundwater resources (Alberta Energy Regulator, 2003).

Proper classification of leak severity is important since this classification determines when a remedial workover is required. If a vent flow is deemed to be serious, then remedial work is required to begin within 90 days of discovery. Conversely, if the vent flow is considered non-serious, then repairs may be deferred until final abandonment. The only stipulation is that non-serious vent flows must be tested annually over a five-year period or until the leak dies out to ensure that the leak does not become serious (Alberta Energy Regulator, 2003).

The Alberta Energy Regulator has adopted an electronic data capture system for Digital Data Submission (DDS), which industry is required to use to submit leakage reports. Any vent flow detected must be submitted to this system within 30 days. Annual testing of non-serious vent flows is not required to be submitted, unless the leak becomes serious (Alberta Energy Regulator, 2003).

GM follows similar requirements to SCVF, with the exception that testing requirements are not widespread. The only wellbores that are required to be tested for GM are those which fall within a problem area, often referred to as the Test Area in east-central Alberta (Figure 2.5). While GM testing is not enforced in areas outside of the Test Area, the Alberta Energy Regulator recommends that industry test for GM at the time of final abandonment (Alberta Energy Regulator, 2003).

2.4.2 Testing Methodology

Whereas the AER outlines what must be monitored and when monitoring must be performed, the methodology industry uses to meet these minimum requirements is unregulated. The AER only requires that industry use an acceptable approach and that the method used be outlined for review upon request (Alberta Energy Regulator, 2013).

Although the AER does not regulate monitoring methodologies, an endorsed method is outlined in the appendices of Directive 020 (Alberta Energy Regulator, 2013). SCVF are most often tested by performing a bubble test, as shown in Figure 2.6. This is usually accomplished by directing gas flow from the surface casing vent through a small hose (minimum 6 mm, maximum 12 mm inside diameter) into a container of water. All valves in the vent line must be open and the hose must be submerged into the water a minimum of 2.5 centimeters. The container is then monitored over a 10-minute interval for gas flow by noting the formation of any bubbles in the water (Alberta Energy Regulator, 2013).

If gas flow is detected during the bubble test, the flow rate and the stabilized shut-in surface casing pressure must then be determined. For measuring flow rate, equipment selection is de-

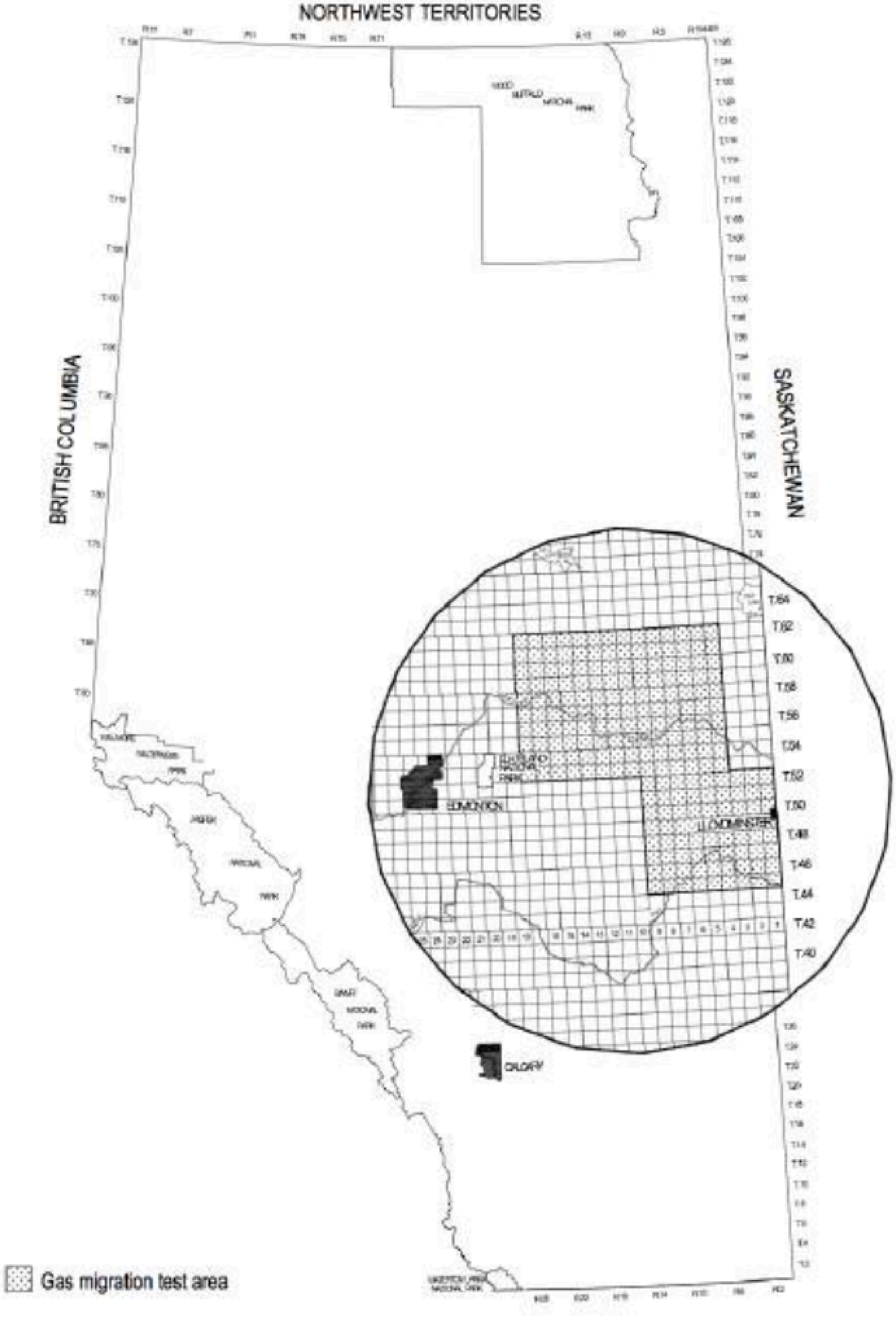

Figure 2.5. Location of the GM Test Area in Alberta. Included are (a) Townships 45-52, Ranges 1-9, West of the fourth Meridian; (b) Townships 53-62, Ranges 4-17, West of the fourth Meridian.

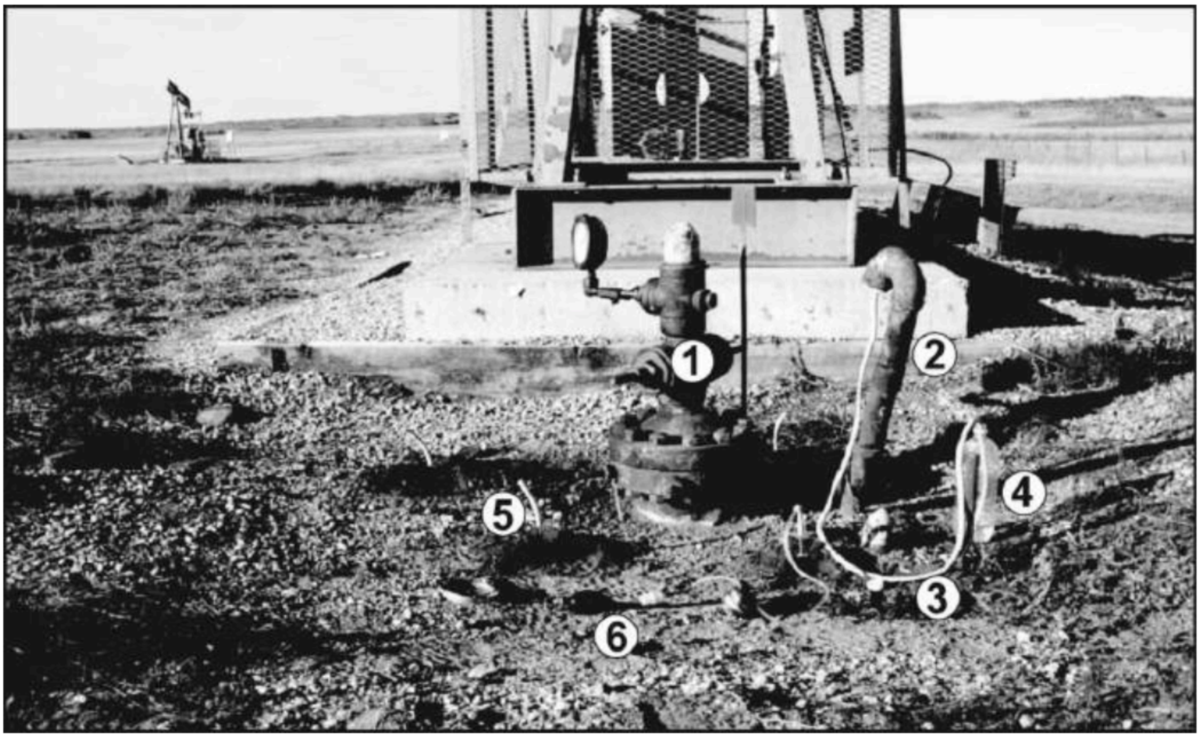

Figure 2.6. Bubble test (2-4) and GM survey (5-6) for testing SCVF and GM, respectively (from Watson and Bachu, 2009).

pendent on the expected values from the bubble tests. Accurate measurement of low flow rates requires the use of positive displacement meters, whereas higher flow rates may be measured using orifice well testers. For determination of stabilized shut-in surface casing pressures, the AER recommends the installation of a pressure recorder or gauge and a pressure relief valve (Alberta Energy Regulator, 2013).

Similarly to a SCVF, the methodology for testing for GM is not regulated, but the AER endorses the methodology outlined by the Lloydminster Area Operations Group Gas Migration Team (LAOGMT). As shown in Figure 2.6, a GM survey is generally performed by drilling approximately 50 cm deep and maximum 6.4 cm diameter holes strategically around a wellhead at points that ensure GM is detected. Placement recommendations include: two points within 30 cm of wellhead on opposite sides; at two meter intervals outward from the wellbore every 90^o (a cross with the wellbore at centre) to a distance of six meter; and at any points within 75 m of wellbore where there is apparent vegetation stress (e.g., dead grass). At each of these points, the hole is isolated from atmospheric gases using a chamber or dome-like structure. After ensuring equipment is properly calibrated and that there are no leaks allowing the mixing of atmospheric gases, the lines and equipment are purged and a soil sample is extracted.

2.5 Wellbore Leakage Remediation

2.5.1 Repair Requirements

As outlined by Alberta Energy Regulator (2003), the time at which wellbore leakage repairs must be performed is dependent on the severity of the leak. All leakage problems that are considered serious must begin remedial work as soon as possible and no later than 90 days after initial detection. Repair of non-serious vent flows may be deferred until final abandonment as long as the leak is monitored for a five-year period and the leak does not become serious.

Routine well repairs are those where: i) the source depth or formation of origin is clearly identified using a method acceptable to the AER (e.g., gas analysis, noise/temperature surveys, logs); ii) fluid flow is eliminated by perforating and cementing (i.e., perf- and squeeze) the casing(s) at or below the source using cement that meets the minimum cement requirements outlined in Alberta Energy Regulator (1990); and iii) the casing is pressure tested to a maximum operating pressure for ten-minutes with no pressure drop recorded (Alberta Energy Regulator, 2003).

If a workover plan deviates in any way from the above criteria, or if initial repair attempts were unsuccessful, the repair is then considered non-routine. Non-routine repairs, unlike routine repairs, require the AER's approval. Non-routine repairs are required to include: i) the method used to identify the source of the SCVF/GM flow; ii) all relevant logs; iii) casing and cementing details; iv) base of groundwater protection depth; v) complete details of the proposed repair program; vi) proposed perforating depth, if greater than ten-meters above the identified source; and vii) summary of initial operations to repair the flow.

While generally repair of serious leaks is required, industry may be granted the opportunity to defer repair if the licensee has exhausted all attempts to completely eliminate the fluid flow. Alternatively, the AER may grant industry the right to produce fugitive gases if a number of conditions are met (Alberta Energy Regulator, 2003).

2.5.2 Identifying the Source of the Problem

The success of a remedial workover is highly dependent on first correctly identifying the source of the problem to ensure that appropriate remediation procedures are taken. Clearly identifying the source depth or formation of origin is also a requirement for routine well repairs (Alberta Energy Regulator, 2003). The source of the problem may be identified using several direct and indirect methods:

Isotopic Depth Profiles The use of carbon isotope ratios ($^{13}C/^{12}C$) for defining the origin of methane in groundwater systems is well developed in the literature. Generally, methane that is isotopically depleted (i.e., less than or more negative than $\sim$-50‰) in regards to $\delta^{13}C$ relative to the Pee Dee Belemnite (PDB) standard is biogenic in origin (Barker and Fritz, 1981; Révész et al., 2012). Conversely, methane with an enriched (i.e., greater than or more positive than $\sim$-50‰) isotopic signature in regards to $\delta^{13}C$ relative to the PDB standard is thermocatalytic in origin. Since the source rock, geological history and maturity of hydrocarbons can vary significantly between adjacent formations, thermocatalytic hydrocarbons of different origin can further carry distinctive isotopic signatures (Schoell, 1980; Révész et al., 2012).

Given isotopic variations between hydrocarbons of various origins, such distinctions can be exploited for identifying the possible source of fugitive gases found leaking from energy wellbores. This can be accomplished by establishing an isotopic depth profile – a profile summarizing the isotopic characterization of every hydrocarbon source penetrated by the wellbore with depth – in a given area to use as a catalogue or footprint for comparison against fugitive gases (Rich et al., 1995; Muehlenbachs, 2012, 2013; Taylor et al., 2000).

Isotopic depth profiles are usually developed by performing mud gas logging during the initial drilling of a wellbore. Essentially, as drilling proceeds, bits of rock containing embedded gas are broken up and circulated to the surface within the drilling mud. Once at the surface, a mud gas sample can then be extracted and analyzed to determine its isotopic composition. The depth of the gas can be deduced based on the fluid circulation rate and the depth of the drill bit (Rich et al., 1995; Rowe and Muehlenbachs, 1999; Taylor et al., 2000).

An exemplary application of an isotopic depth profile for identifying the possible origin of fugitive gases is given by Rowe and Muehlenbachs (1999). In this study, the isotopic signature of fugitive gases best correlated to the isotopic signature of formation gases at a depth of 350 m (Figure 2.7).

The use of isotopes has advantages over other possible geochemical analyses. For instance, the bulk chemical composition of thermocatalytic and biogenic hydrocarbons has been used to discriminate the origin of the gas. This is based on the fact that thermocatalytic derived hydrocarbons contain ethane and other higher chained hydrocarbons, whereas biogenic derived hydrocarbons contain primarily methane with perhaps trace amounts of ethane (Barker and Fritz, 1981; Taylor et al., 2000). However, as discussed by Bernard et al. (1976), these characteristics can be altered as a consequence of migration and biodegradation. Consequently, a bulk chemical analysis of hydrocarbons can produce unreliable results. For this reason, carbon isotope ratios are much more useful for determining the origin of methane.

While the use of isotopes can be a useful tool for determining the origin of fugitive gases, there are also a few limitations to their use. Perhaps the greatest limitation is that the use of isotopes requires that there be a well-established isotopic depth profile, which unfortunately is frequently not the case in many areas. In fact, the British Columbia Oil and Gas Commission consider other means of source identification more useful than isotopic depth profiles, because the lack of reliable information (i.e., poorly characterized formations) has led to uncertain and even contradictory findings (British Columbia Oil and Gas Commission, personal communications, January 14, 2014). Isotopic signatures of hydrocarbons can further be altered as a result of biodegradation or mixing of gas with other sources, further complicating the process (Rich et al., 1995).

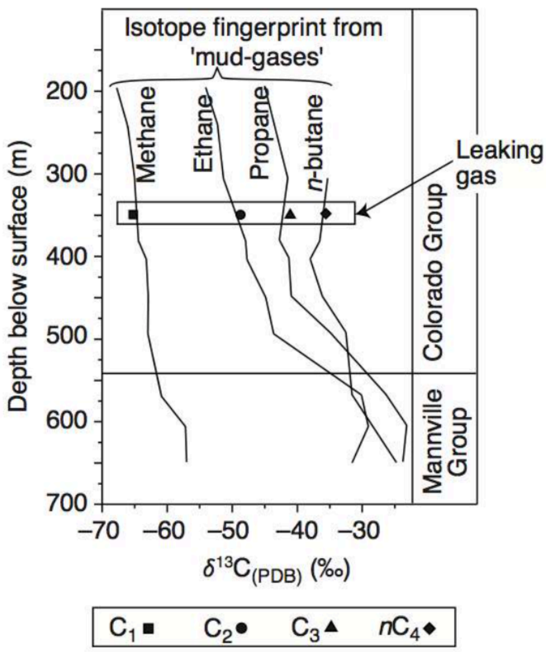

Figure 2.7. Isotopic composition of a fugitive gas sample superimposed on an isotopic depth profile (Rowe and Muehlenbachs, 1999)

Another issue with the use of isotopic depth profiles is that such analyses provide no insight about a possible leakage pathway. Rather, the use of isotopes may only constrain the possible source of the problem to a particular interval (or formation), which may be a few hundred meters in length. Whether the fluid is flowing through a microannular channel, a discontinuity in the cement, or some other pathway where remediation is required, cannot be determined. For these reasons, isotopic depth profiles are best used in conjunction with other methods such as wireline tools.

Wireline Tools Wireline tools are commonly used by industry to indirectly identify fluid migration pathways. The most commonly used tools include cement bond logs (CBLs) and noise and temperature logs, which serve various purposes such as detecting discontinuities in the cement sheath and detecting flow behind the casing (Dusseault et al., 2000; Slater, 2010).

CBLs are used to evaluate the quality of cement behind a casing string for the purpose of identifying possible migration pathways. A transmitter emits an acoustic-wave signal that travels through a section of the casing, and the returning energy (reflection) is detected by a receiver. The receiver measures the arrival time and degree of attenuation of the wave, i.e., the loss of acoustic energy as the wave propagates through casing (Bybee, 2007). The attenuation of the wave-signal is a reflection of the cement quality (e.g., good, moderate, poor or inexistent) behind the casing, because the acoustic impedance of the wave varies between areas of good and poor cement quality as well as with the presence of void spaces. Ultimately, CBLs indicate the fraction of the casing perimeter covered by cement and can help locate void spaces where a cement squeeze may be required (Bybee, 2007; Bellabarba et al., 2008; Nelson, 2012).

Noise and temperature logs are used to identify leakage points behind the casing. Gas flow behind the casing produces noise at a diagnostic frequency, which can be detected by highly sensitive microphones (McKinley et al., 1973; Slater, 2010). In addition, downhole measurements of temperature gradients can be used to identify anomalies that may be indicative of GM. Noise and temperature logs are often used in conjunction (Slater, 2010).

Although wireline tools offer a relatively effective method for identifying potential subsurface leakage pathways for formation fluids, they have limitations. CBLs, through technological advances, have become increasingly reliable at correctly identifying problem areas; however, these tools still on occasion provide ambiguous results. This is a problem that even properly used and calibrated tools may encounter, because there are a number of factors that can adversely affect the quality of a log (Bybee, 2007; Bellabarba et al., 2008). As outlined by Bybee (2007), the major impact factors that may influence log quality include: the presence of a microannulus; casing eccentricity; logging-tool centralization; fast formations (i.e., very high velocity, short transit time); lightweight cement (low contrast between formation fluid and cement slurry density); and cement setting time (analyzing cement before slurry has fully set).

The effectiveness of noise and temperature logs for identifying leakage behind the casing remains controversial. Some experts feel these tools are an essential aid in gas leak identification, while others feel these tools are unreliable (Arthur, 2012). In order for a noise log to detect (i.e., hear) leakage, the noise of the gas leakage must be louder than ambient background noises. If the background noise is louder than gas leakage, then the frequency structure of the noise must be analyzed (Arthur, 2012).

Perhaps the greatest limitation of wireline tools is that current technology is ineffective at evaluating cement quality beyond one casing string, and is therefore limited to assessing the cement sheath immediately behind the interior-most casing (Saponja, 1999; Bellabarba et al., 2008). Consequently, there are outer sections of the wellbore that cannot be assessed using wireline tools if there is more than one concentric casing string, as in the surface casing – production casing system in the upper shallow section (Figure 2.3). Furthermore, the possibility of seepage through the surrounding formations (e.g., pre-existing pathways) cannot be detected by within-the-casing methods.

Noble Gases Noble gases offer a unique opportunity to trace subsurface migration pathways of fluids because of their inert nature and distinguishable fingerprints between various origins (e.g., atmosphere, hydrosphere and lithosphere) (Darrah et al., 2014). Unlike hydrocarbon gases, noble gases are unaffected by microbial or chemical processes (i.e., they are inert) and therefore the only alterations in their isotopic fingerprint is attributed to well-constrained physical processes including diffusion and phase partitioning as the gases migrate through the subsurface. Depending on the migration pathway, e.g., through a poorly sealed energy wellbore or through a pre-existing pathway, the degree of fractionation varies, but in a predictable manner; fractionation is expected to be significant for fluid migration through water-saturated media compared to a pathway through a poorly sealed energy wellbore (Darrah et al., 2014).

Noble gases were recently used in a study by Darrah et al. (2014) to determine the subsurface migration pathway of thermogenic methane that was detected in shallow groundwater near shale gas development operations of the Marcellus and Barnett shales. The authors used the expected variations in isotope fractionation to show that the presence of gas in the groundwater was most likely the consequence of a well integrity problem, rather than a hydraulically induced fracture or pre-existing pathway.

2.5.3 Cement Squeezes

Following the determination of the source of a problem, the next step in the remedial process is a cement squeeze. As outlined by Van Dyke (1997), the problem area (as identified by wireline tools, isotopes and noble gases) is perforated using a perforation gun to generate holes through the casing, cement and formation rock. A sealing agent, typically cement, is subsequently squeezed into the void space with the goal of intercepting the leakage pathway. A bradenhead squeeze, as shown in Figure 2.8, is one squeeze method, where a cement plug or mechanical packer is placed below the perforation and cement slurry is pumped down a tube filling the perforated area with cement. The casing is then sealed off with a valve or a packer to elevate pressure as cement is continuously pumped through the tube. Ultimately, this results in cement being squeezed into the perforations and if successful, generating the desired seal. If unsuccessful, the process is repeated until an adequate seal is achieved (Bradford and Reiners, 1985; Chmilowski and Kondratoff, 1992; Van Dyke, 1997; Nelson, 2012; von Flatern, 2012).

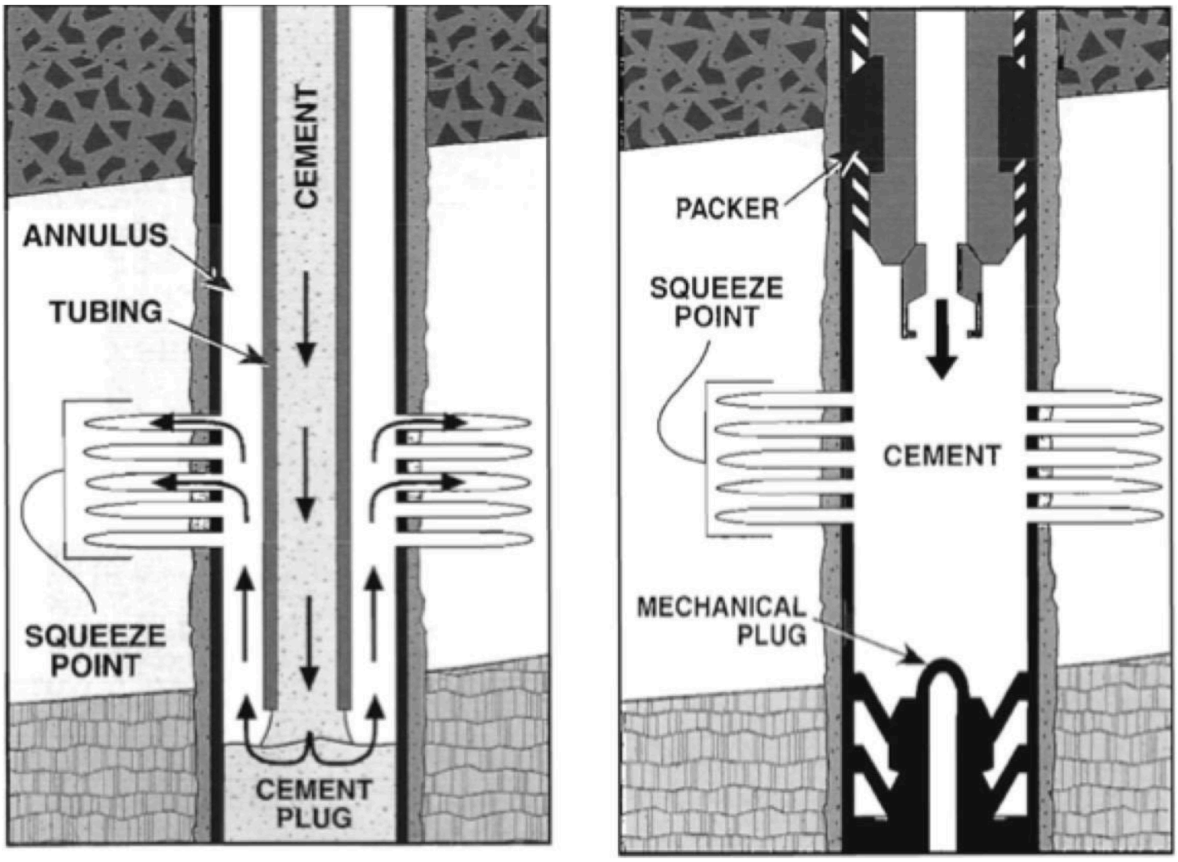

Figure 2.8. Schematic of a bradenhead squeeze (left) and a packer squeeze (right) (Van Dyke, 1997)

While under suitable conditions a cement squeeze may be a straightforward process (Chmilowski and Kondratoff, 1992), the procedure can be challenged by formation conditions and fracture apertures, which may limit the effectiveness of the remedial operation. Formation conditions influence the success of a cement squeeze because the formation conductivity and pore pressure control the "formations resistance to injectivity" (Chmilowski and Kondratoff, 1992). On one hand, extremely permeable formations or formations containing large vugs and large fractures may not support a cement column, as cement slurries may flow unimpeded into the formation. Conversely, geological materials with low permeabilities or swelling properties (e.g., swelling clays) can significantly limit the feed rate of the cement slurry into the void space and consequently result in cement hydration immediately at the perforations. For similar reasons, the size of the aperture can also challenge the placement of the cement slurry in the void space (Chmilowski and Kondratoff, 1992; Saponja, 1999; Watson et al., 2002).

As discussed by Dusseault et al. (2014), cement squeezes can present other challenges, particularly in stiff, naturally fractured rocks. Establishing sufficient feed rates to allow the cement slurry to fully penetrate the void space can be difficult, and consequently higher pressures may be applied to effectively force the cement slurry into the perforation. However, if these pressures exceed the formations fracturing pressure, small (20-50 μm aperture) fractures may form. This means that as one void space is filled, several others may form as a result.

Given the challenges of remedial workovers, avoiding the need to undergo a repair in the first place is most desirable. However, for reasons discussed in Section 2.6, wellbore leakage may still develop despite best efforts to adequately construct the wellbore. Well repairs cost on average $150,000 per well (K. Parsonage, personal communication, 2014), with some remedial costs exceeding millions of dollars, as well as lost production time during the repair process (see Dusseault et al., 2014 and references therein).

2.6 Mechanisms of Wellbore Leakage Development

As early as the 1960s, researchers were interested in identifying the underlining mechanisms responsible for the development of wellbore leakage. Issues encountered during the initial construction of the wellbore have been consistently identified as the leading causes of leakage problems, but also issues encountered later over the life of the well. The following section outlines the principal mechanisms of leakage development identified in literature during the initial construction of the wellbore, during the operational life a well, and after final abandonment.

2.6.1 Poor Construction and Completions

During the initial construction of the wellbore, it is important that proper care is given to ensure that properly designed cement slurry is placed evenly around the casing strings and that the cement is free of contaminants. Failure to do so may result in the formation of void spaces and microannuli in the cement sheath, which may ultimately affect the ability for cement to provide an adequate seal. These issues may arise as a consequence of improper cement slurry or drilling fluid design, inadequate drilling fluid removal, or the invasion of formation fluids.

Improper Drilling Fluid and Cement Slurry Design Drilling fluids serve several important purposes, including cleaning drill cuttings from the borehole, reducing friction between the drill string and formation wall (i.e., preventing washed-out areas), and preventing fluids held within adjacent permeable formations from entering the borehole (see Section 2.1). However, in order for the drilling fluid to work effectively, the fluids must be carefully designed to meet the geological and borehole conditions. In particular, careful attention to drilling fluid viscosity and density is needed, because these properties play the most significant role in ensuring that the fluid can adequately transport drill cuttings out of the wellbore while at the same time causing minimal damage (e.g., washed out areas and formation fracturing) to the surrounding borehole wall. If the drilling fluid is not viscous or dense enough, drill cuttings may not be adequately displaced and the hydrostatic pressure may be insufficient for preventing the influx of formation fluids. Conversely, if the viscosity and density are too large, the pressure of the drilling fluid column may be too large, which may significantly impair the transport of drill cuttings, while further inducing washed-out areas and fracturing the borehole wall if the lateral stresses in the formation are lower than the drilling fluid density (Baker, 2001; Brufatto et al., 2003).

The cement slurry must also be appropriately designed to meet the conditions in the borehole. The cement slurry must be adequately mixed and placed at an appropriate density, typically around 2.0 Mg/m^3 (Dusseault et al., 2000). Since wellbore conditions are highly variable, a number of additives such as accelerators and retarders (to control set times), extenders and weighting agents (to control densities), fluid loss and lost circulation additives (to reduce water expulsion from the setting cement into surrounding permeable formations), and dispersants (to control viscosity) are required. If the cement slurry is not appropriately designed, then an adequate bond may not form between the cement and the casing/borehole wall regardless of quality control during placement (Watson et al., 2002; Macedo et al., 2012)

Inadequate Drilling Fluid Removal Drilling fluids, if not adequately displaced from the borehole prior to the placement of the cement slurry, may result the formation of a microannulus. As discussed by Dusseault et al. (2000), cement is known to not form bonds with various materials such as salt, oil-rich beds such as oil sands, high porosity shales, and residual drilling fluid, i.e., drilling mud filter cake. Therefore, in order for a strong long-lasting bond to form between the cement-casing and cement-borehole wall interfaces, the surface must be water-wet and thus clean (Dusseault et al., 2000; Zhang and Bachu, 2011). However, if the casing strings and borehole wall are not adequately cleaned of drilling fluid prior to placement of the cement slurry, then the residual drilling fluid may inhibit the formation of a cement bond and consequently a microannulus may develop.

In addition to cleaning the casing strings and borehole wall prior to placing the cement slurry, care must also be given to ensure that drilling fluid does not intermingle with the cement slurry. As discussed by Bittleson and Dominique (1991), if a water-based drilling fluid dominated by sodium ions comes in contact with calcium-rich cement slurry, then massive flocculation and solidification can immobilize the drilling fluid, making it difficult to remove. If some drilling mud becomes mixed into the cement slurry, it may prevent gelation from occurring, reduce the compressive strength of the set cement, or the drilling mud may dehydrate over time leaving behind a void space that may provide a conduit (i.e., a channel) to formation fluids (Watson, 2004; Zhang and Bachu, 2011).

Drilling fluid is generally effectively displaced from a borehole by using straight-forward tools such as wipers and scrapers (Bellabarba et al., 2008; Macedo et al., 2012). However, the process can be complicated as a consequence of washed-out areas, which are often difficult to adequately penetrate and clean. Similarly, poor casing centralization further increases the difficulty of adequately displacing drilling fluid. As illustrated in Figure 2.9, on the narrow side of an eccentric casing, particularly if the casing is in direct contact with the exterior casing or borehole wall, it is difficult to adequately displace the drilling fluid because turbulent displacement will be inhibited. Furthermore, the cement slurry will preferentially flow up the wider side of the annulus, and therefore the cement will be placed unevenly around the casing string (Bellabarba et al., 2008; Roth et al., 2008).

Figure 2.9. Microannulus resulting from poor drilling fluid displacement. An eccentric casing significantly exacerbated the problem (Watson, 2004)

Invasion of Formation Fluids Once the cement slurry has been placed, the cement generally requires several hours of gelation until the cement has developed sufficient strength to resist the invasion of formation fluids. While initially the cement slurry has a higher hydrostatic pressure than the surrounding formations, cement shrinkage, early or uneven gelation, sedimentation and the bridging of particles result in a reduction of this hydrostatic pressure (Brufatto et al., 2003; Stein et al., 2003; Macedo et al., 2012). If the hydrostatic pressure of the slurry falls below the hydrostatic pressure of the surrounding formations, the cement will become vulnerable to invasion of fluids which consequently may result in the development of channels (Figure 2.10).

Figure 2.10. Channels formed in cement sheath as a result of fluid invasion during cement set (Watson, 2004)

2.6.2 Operational Stresses

The initial construction of the wellbore is important for ensuring an adequate seal is acquired initially. However, regardless of initial construction, there still remains the possibility that wellbore leakage may develop. This may occur during the active operational life of the wellbore or long after abandonment.

The active life of the wellbore is when the highest mechanical stress levels are imposed on the casing and cement. During injection or production, the casing may expand and consequently compresses the cement sheath, increasing the radial compressive stress on the cement. When injection or production stops, the pressure may build up or be released, and this affects the radial stress in the cement sheath. This process, if continued over time, can result in cement fatigue where radial stress cracks may develop (Figure 2.11), or the cement may "de-bond" from the casing or borehole wall, leading to the development of a microannulus (Goodwin and Crook, 1992; Dusseault et al., 2000; Zhang and Bachu, 2011). In addition to mechanical stresses, wells used for enhanced oil recovery operations are further exposed to thermal stresses, and consequent thermal shock may increase the likelihood of microannulus and fracture development (Bour, 2005; Watson and Bachu, 2009).

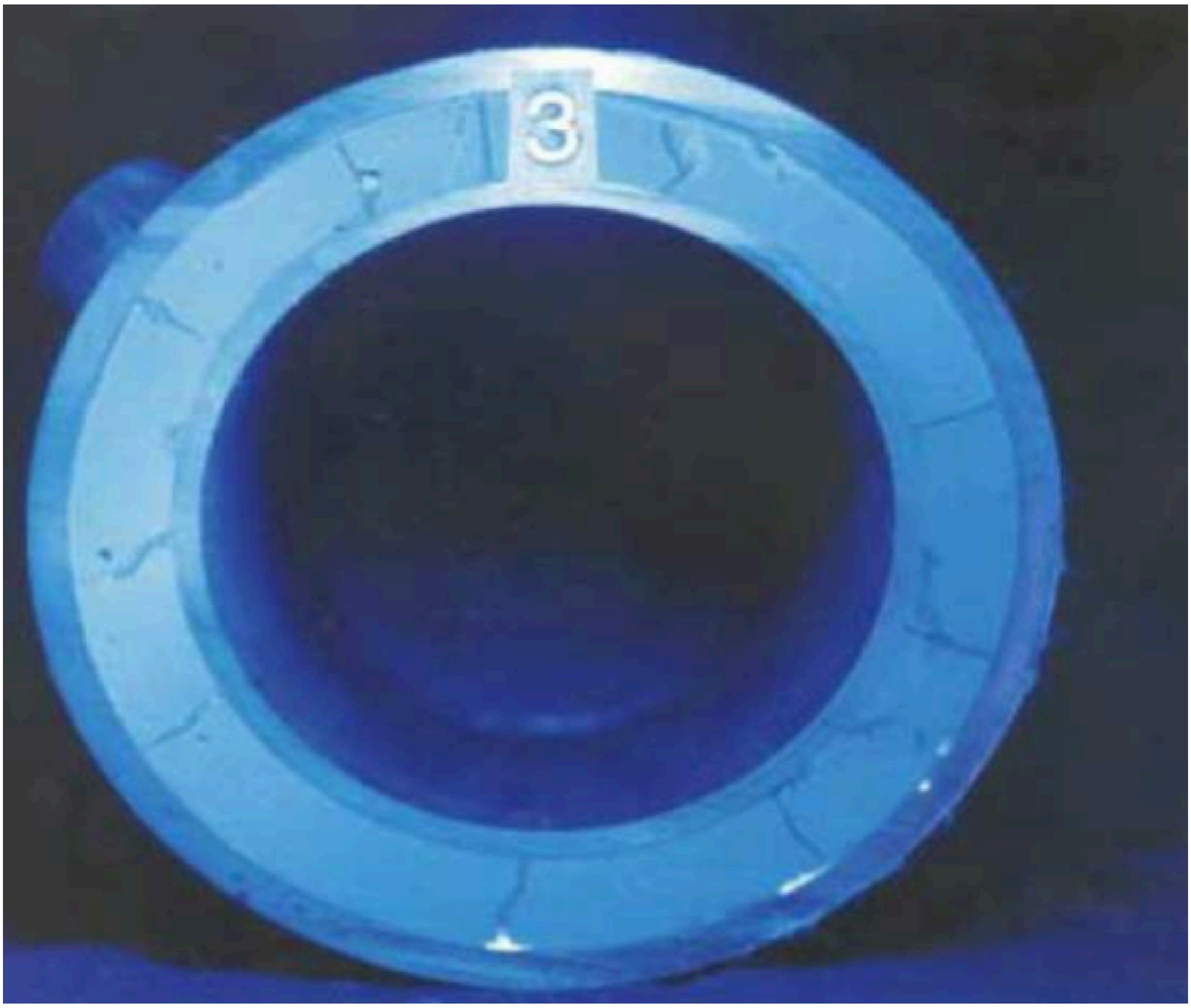

Figure 2.11. Radial stress cracks induced from casing expansion (Watson, 2004)

2.6.3 Abandonment Failure

Wellbore abandonment approaches are meant to be robust and therefore capable of maintaining an adequate seal for many years. However, this requires that the abandonment design is capable of lasting for many years. Some abandonment methods are more effective than others at providing a long-term seal. For example, an investigation (Watson and Bachu, 2009) into the long-term durability of bridge plugs – the most common abandonment method used in cased and completed wellbores in Alberta – among a small subset of wellbores abandoned using this method found that bridge plugs were highly vulnerable to corrosion because they are comprised of cast iron and nitrile elastomers. Furthermore, the cement plug placed over the bridge plug in many of these wells "...was not evident, even though a tour-report review indicated that the cement had been dump bailed on the bridge plug" (Watson and Bachu, 2009). Based on these observations, the authors suggested that approximately 10% of wells abandoned using a bridge plug would fail over a long period of time (hundreds of years), and subsequently allow formation fluids to enter the wellbore. Thus, wellbores abandoned using a bridge plug are more likely to develop leakage problems than other abandonment methods such as the balanced-plug method or a cement squeeze using a retainer.

Cement shrinkage, in addition to leading to a loss in cement slurry hydrostatic pressure, may further play a role in the development of leakage problems long after well abandonment. Oil and gas wells are most often constructed using a Portland-based cement (Dusseault et al., 2000), which by nature undergoes shrinkage because the products of the hydration reaction are of a lesser volume than the reactants (Ravi et al., 2002; Stein et al., 2003). This shrinkage, often referred to as "autogenous shrinkage", in addition to other mechanisms of bulk shrinkage such as dehydration – the expulsion of water from the cement slurry to surrounding permeable formations – and in some cases osmotic dewatering, reduces the total radial stress between the cement and the borehole wall to less than pore pressure. This leads to differences between lateral stress and fluid pressure gradients, which consequently result in the formation of circumferential fractures (microannular spaces) that grow vertically over time. The development of such narrow aperture channels is further reinforced because of an upward driving displacement pressure due to gas buoyancy, which increases as the fractures become more gas-filled over a substantial height (Dusseault et al., 2000).

2.7 Previously Identified Factors Influencing Leakage Development

Wellbore leakage has been identified as a first-order risk for carbon dioxide sequestration operations because poorly sealed offset wellbores penetrating the storage reservoir may provide a conduit for carbon dioxide to the surface. Given these concerns, Watson and Bachu (2009) were interested in identifying factors that could be used to predict which wellbores were most likely to leak or presented the greatest liability following future abandonment.

To identify these factors, the authors compiled a database, which comprised the AER (Energy Resources Conservation Board at the time) SCVF and GM reports and supporting deep well information for wells drilled across Alberta (e.g., casing size, casing weight, borehole depth, completion intervals, production method, abandonment method, stimulation, gas composition, and geological formations). This database was then data mined to "...provide a baseline of known wellbore leakage against which potential indicators could be evaluated" (Watson and

Bachu, 2009). The authors further considered regulatory changes and other external factors that could have influenced the prevalence of leakage development. This section outlines the major findings of the study and provides a summary of the factors investigated.

2.7.1 Factors Showing Major Impact

Geographic Area Wellbores located within the Test Area of the Province were found to be more problematic than elsewhere across the province (Watson and Bachu, 2009). This finding may have been the result of the extra monitoring requirements within this region, leading to a higher percentage of problems being reported. However, as discussed by the authors, the extra testing requirements are presumably attributed to the fact that the area is known to have GM problems, and that the findings are likely an accurate reflection of higher leakage occurrences in the area.

Wellbore Deviation Considering only wellbores drilled within the Test Area, deviated wellbores were found to be more prone to leakage problems than all wellbores. The form of leak that developed (i.e., SCVF or GM) was not found to be influenced by well design.

Well Type Watson and Bachu (2009) identified two main types of wellbores in Alberta; those that were drilled and abandoned and those that were drilled, cased and abandoned. The authors found that wellbores that were drilled and abandoned had a much lower occurrence rate of leakage compared to those that were drilled, cased and abandoned (0.5% and 14%, respectively). Drilled, cased and abandoned wellbores accounted for 98% of all leakage reports. The authors attributed this finding to an additional leakage pathway among wellbores that were drilled, cased and abandoned, and also more stringent abandonment requirements for drilled and abandoned wells historically.

Abandonment Method In Alberta, there are three main methods that are commonly used to abandon wellbores: (1) bridge plug capped with cement; (2) cement plug placed across completed intervals using a balanced-plug method; and (3) squeezing cement into perforations. As discussed by Watson and Bachu (2009), wellbores abandoned using bridge plugs capped with a cement plug placed by the dump-bail method are unreliable for providing a seal for many years or decades (see Section 2.6.3). Therefore, depending on the abandonment method used, some wellbores may be more vulnerable to the development of leakage problems.

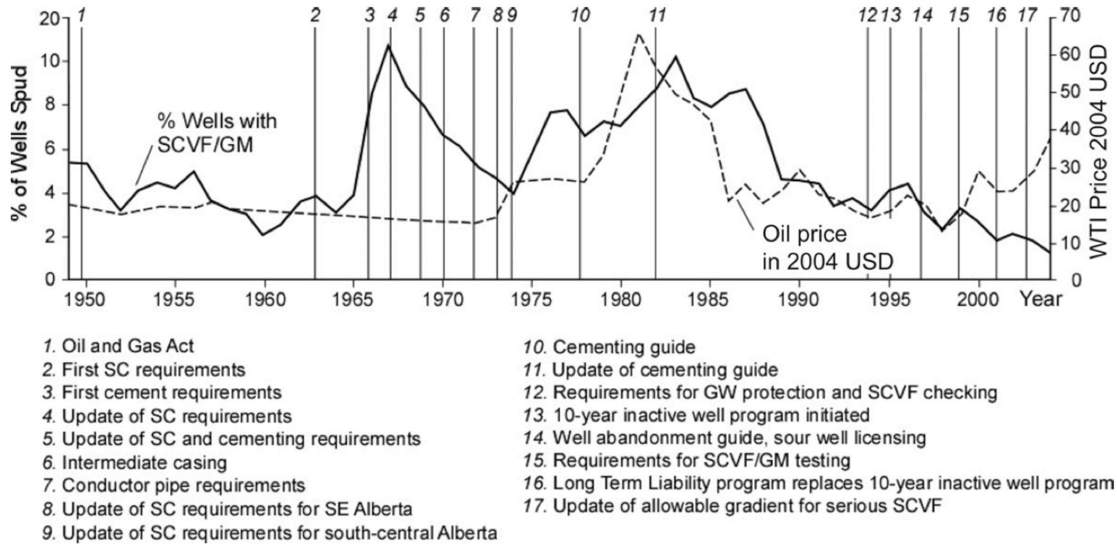

Figure 2.12. Timeline of important regulations introduced by the AER to mitigate wellbore leakage. Plotted with the time line are historical oil prices and the percent of wells spud per year (Watson and Bachu, 2009).

Oil Price, Regulatory Change, and SCVF/GM Testing Figure 2.12 shows the occurrence rate of wellbore leakage (indicated by the number of wells spud per year with leakage problems), drilling activity (indicated by oil prices) and the dates of important regulation changes in Alberta. Watson and Bachu (2009) found a strong correlation between the occurrence rate of wellbore leakage and drilling activity. They suggested that "...the pressure to do more with less..." may be largely responsible for this observation, because with higher oil prices, there is a higher drilling incentive. This may consequently impact both equipment availability and well construction practices used in the field. Furthermore, with higher oil prices, there is greater incentive to develop heavy oil pools, which require the drilling of non-vertical wellbores and stimulation techniques that increase the likelihood of leakage problems.

Watson and Bachu (2009) observed that the relationship between drilling activity and the occurrence rate of wellbore leakage began to diminish after 2000. They attributed this observation to a change in monitoring regulations that was implemented in 1995. Furthermore, since many of the wellbores spud after 1999 were still active at the time of analyses, they have not been tested for leakage since initial drilling rig release and for leakage that may have developed during the operational life of the wellbore.

Uncemented Casing/Hole Annulus Low cement tops or exposed casing was identified by Watson and Bachu (2009) to be the most important factor related to the development of wellbore leakage, because most leakage problems originated from a depth above the cement top. Not having a protective cement barrier further leaves the steel casing vulnerable to corrosion, and the majority of casing failures occurred where cement was not present or of poor quality. Based on cement bond logs and experience, the authors noted that the top 200 m of the cement annulus is often of poor cement quality, with the best quality cement located deeper in the well and across completed intervals.

2.7.2 Factors Showing Minor Impact

Licensee Watson and Bachu (2009) speculated that various construction practices used by different companies would be reflected in the occurrence rate of leakage. To explore this, wells drilled by two companies in a particular area were compared. There was a clear difference in the incidence of SCVF and GM between the two licensees. Factors such as a company's internal standards for testing and reporting may have influenced the reliability of the data.

Surface Casing Depth Although Watson and Bachu (2009) did not find a relationship between surface casing setting depth and whether or not leakage would develop, they did find a strong relationship between casing depth and the form of leakage (i.e., SCVF or GM) that developed. Wells with shallower surface casing setting depths were generally found to develop SCVF and the occurrence of GM increased as surface casing setting depth increased. In addition, this finding further indicated that GM usually originated from a source located above the surface casing shoe.

Total Depth Watson and Bachu (2009) found that deeper wells had a slightly higher occurrence rate of wellbore leakage than shallower ones, possibly as a result of larger uncemented intervals.

Well Density In areas where multiple wellbores are located in close proximity to one another, the likelihood of having interwellbore communication is much higher. Watson and Bachu (2009) found no evidence in their database to support this, but retained its importance because it had been recognized as an important factor in other studies.

Topography Anecdotal evidence and also some well documented cases (e.g.. Bellis et al., 2004) have reported serious leakage problems from wellbores located in or near river valleys. These observations may in fact be reflective of a decrease in available hydrostatic pressure that controls flow to the surface from thin gassy zones. This occurs as a result of the removal of overburden and consequently elevation in the area (Gonzalo et al., 2005). Despite discussions in the literature, Watson and Bachu (2009) found no evidence to support a relationship between topography and the occurrence of leakage problems.

2.7.3 Factors Showing No Apparent Impact

Well Age Watson and Bachu (2009) expected age to have a major impact on the prevalence of leakage development for several reasons including historically poorer wellbore construction materials and techniques and changing regulations over time. However, they did not find any evidence to support this, and attributed this to poor monitoring requirements prior to 1995.

Well Operational Mode The operational mode of a wellbore was used by the authors to refer to the operational activities occurring on a wellbore, such as producing oil or gas, injecting water or solvents, disposal of liquid waste or acid gas, or observation. Watson and Bachu (2009) expected increased stress load on some wells to consequently result in higher occurrence rates of leakage (e.g., thermal stresses induced on wells with thermal-operational modes such as steam assisted gravity drainage). While the authors did not find any evidence to support this, they speculated this could be explained by the fact that many of these wellbores are still active and have not been re-tested since initial construction and before operational stresses were induced on the wellbores.

Completion Interval The authors found no correlation between where a well was completed and the source depth of leakage. In fact, the authors noted that generally cement quality is of premium quality near completed intervals, significantly reducing the likelihood of leakage from these areas.

H_2S or CO_2 Presence Since these compounds have the potential to exacerbate casing corrosion, the authors investigated a possible link between the compounds presence and internal and external casing corrosion. No relationship was found, likely because of stringent construction requirements in the presence of these gases.

3 RESEARCH METHODS

3.1 Data Collection

A research database was compiled by integrating energy-well leakage reports with detailed well information. In August of 2014, SCVF and GM reports were obtained from the Alberta Energy Regulator's Products and Services Catalogue (Alberta Energy Regulator, 2015). These reports are a compilation of industry submitted leakage reports, which comprise detailed leakage information including: the report date; well license number; current well license status; surface- and bottom-hole locations; licensee at reporting; report status; leakage type (i.e., SCVF, GM, or both); classification (i.e., serious or non-serious); flow substance; flow rate; stabilized shut-in pressure; source depth; groundwater base; resolution date; and reported resolution. The leakage reports were amalgamated with detailed well information that was extracted from geoSCOUT, a tool that contains a database of public and proprietary well data (http://www.geologic.com/products-services/geoscout). The well data that was extracted from geoSCOUT included: license numbers, spud dates, licensed substance/well objectives (i.e., well types), well designs (i.e., well orientations), drilling contractors, and reported drilling issues.

Each wellbore in the research database was then organized into a corresponding township, based on the bottom-hole location. The term township refers to a 6-mile by 6-mile ($\sim$10-km by 10-km) or 36 mi^2 ($\sim$100-km^2) quadrilateral that is defined, i.e., the location is described, by a township and range pair of numbers following Alberta's Township Survey System (Figure 3.1). The purpose of organizing the wellbores into townships was to better understand the data at a smaller scale by evaluating the influence of factors on the occurrence of leakage problems across the entire Province at multiple locations. For this study, a township was considered to be a sample.

This study focused exclusively on wellbores spud between 2004 and 2013. This period was selected to provide a continuation of previous work in the area by Watson and Bachu (2009), who investigated factors influencing wellbore leakage development for all wellbores completed across the Province up until the end of 2004 (see Section 2.7). Further data exclusions included leakage reports corresponding to confidential wells and also wellbores with missing data for the corresponding analysis.

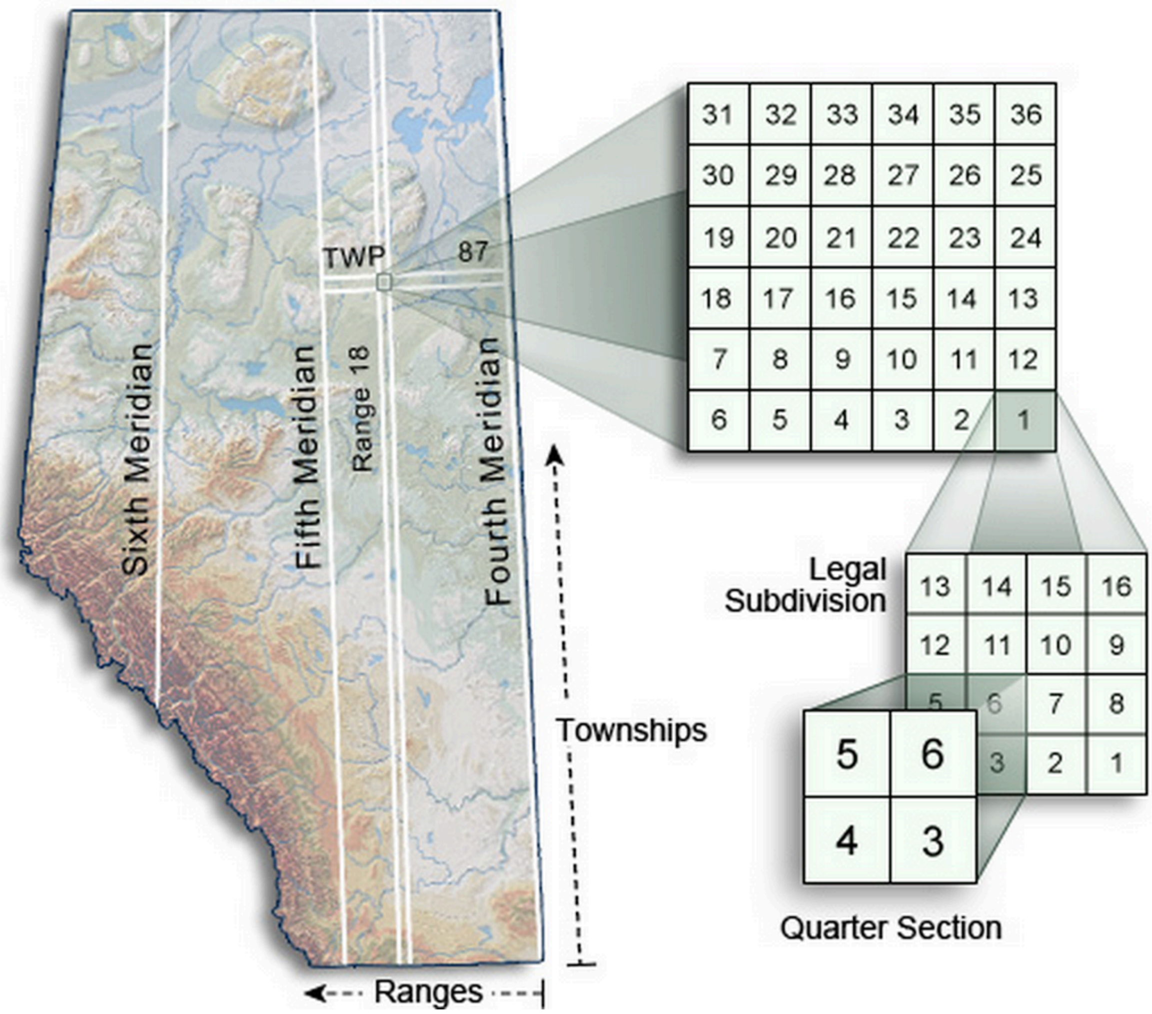

Figure 3.1. Depiction of Alberta's Township Survey System (from the Alberta Environment and Sustainable Resource Development webpage)

3.2 Data Analysis

3.2.1 Study Factors

Several independent variables (herein referred to as "factors") of interest were chosen for the analysis: a) drilling contractor – the contractor that drilled the wellbore; b) well type – the substance that the wellbore was licensed to produce; c) well design – whether the wellbore was drilled vertically or non-vertically (i.e., horizontal or deviated); and d) drilling issues – whether there were or were not reported issues to the AER when the wellbore was drilled.

For the purpose of brevity, this study limited the analysis to five drilling contractors and three well types. The drilling contractors selected for the analysis corresponded to the contractors that drilled the highest total number of wellbores overall during the study period. To preserve the anonymity of these "Major Drilling Contractors", they were assigned a letter from A to E, beginning with the company that drilled the most wells overall.

There were several types of wells documented in the geoSCOUT database: gas, crude oil, crude bitumen, water, brine, coalbed methane, liquid petroleum gas, waste, sand, miscellaneous and undesignated. However, most wellbores spud across the province were licensed to produce gas (excluding coalbed methane), crude bitumen and crude oil. Leakage problems among these type of wellbores were therefore of significant interest. The term "well type" is used throughout this study to refer to gas, crude bitumen and crude oil wellbores.

3.2.2 Descriptive Statistics

Descriptive statistics were applied to the 2004-2013 study period to: a) describe the wellbores spud; and b) describe the occurrence of leakage problems in the wellbores spud (Section 2.4.1). Drilling activity during the study period, i.e., the wellbores completed, was described by the summation of the total number of wellbores spud across all townships, N (the population size). Each factor was described overall (i.e., in regards to all wellbores) and also with respect to the other study factors. More specifically, well design was described overall and with respect to drilling contractor, well type and drilling issues; well type was described overall and with respect to drilling contractor, well design and drilling issues; wellbores drilled by the Major Drilling Contractors were described overall and with respect to well design, type and drilling issues; and wellbores with and without drilling issues were described overall and with respect to drilling contractor, well design and well type. Likewise, the occurrence of leakage problems during the study period were described in the same manner, where the sum described the total number of wellbores that had reported leakage problems across all townships, N.

The time of leakage reporting among wellbores was of interest because it might provide insight about the underlining mechanisms of leakage development. For instance, leakage problems detected prior to the commencement of well production may be indicative of poor primary completions as opposed to operational stresses imposed on the wellbore. The time of leakage reporting among each wellbore was categorized as either: i) before drill rig release; ii) within 90 days of drill rig release; iii) during the operational life of the well; and iv) after final well abandonment. These times were selected based on wellbore leakage monitoring and reporting requirements outlined by the AER (see Section 2.4.1).

3.2.3 Inferential Statistics

It was of significant interest to determine whether there were statistically significant differences in the mean proportion of wellbores spud per township with reported leakage problems among each factor. The selection of an appropriate statistical test to perform these analyses first required an evaluation of the distribution of the data set to determine whether the data are normally distributed. A normally distributed data set by definition has a symmetrical bell-shaped curve about the mean with mean and median values that are approximately equal (Figure 3.2). Conversely, non-normal distributions are not symmetrical about the mean; rather, they are skewed in a particular direction depending on whether the median is larger or smaller than the mean. Common parametric tests such independent samples t-tests and analysis of variance (i.e., ANOVA) require that the data set be at least approximately normally distributed. If this assumption is markedly violated then these tests are not appropriate for use (McClave and Sincich, 2009; Morgan et al., 2013). In such cases non-parametric tests, including Kruskal-Wallis and Mann-Whitney-U tests, might be more appropriate for use since these tests do not require that the data set be normally distributed. The use of these tests require the assumption that: i) the dependent variable has an underlying continuity; and ii) that data are independent (Morgan et al., 2013).

Non-parametric tests, unlike parametric tests, do not require the assumption of normality and their implications are robust to outliers. This is achieved by using a ranking system where data values are ranked from least to greatest rather than using raw values. Therefore the advantage

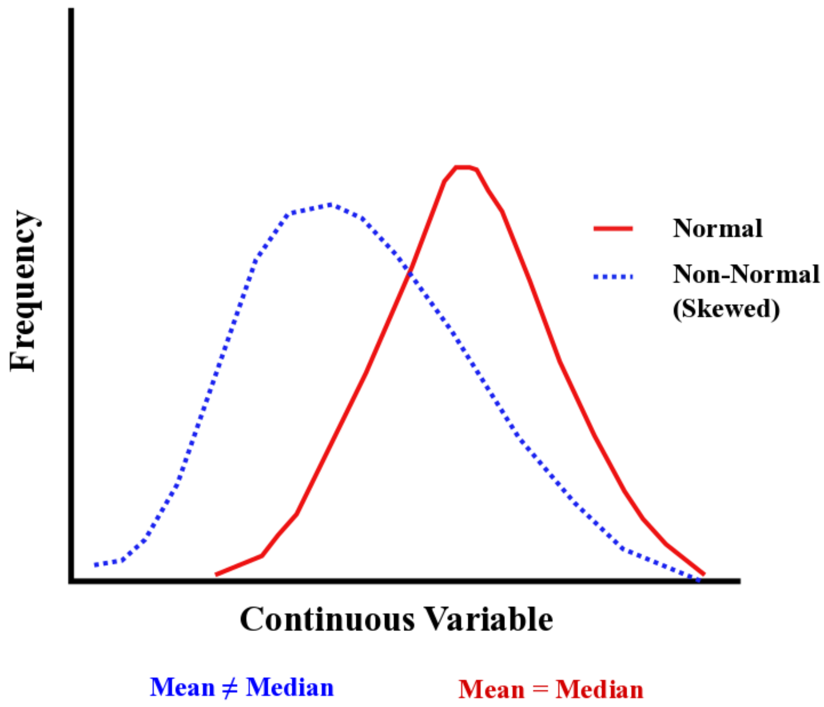

Figure 3.2. Schematic of normal and non-normal (i.e., skewed) distributions.

of using these tests on highly skewed data is that it is irrelevant how much larger one value is than another. Rather, these tests indicate quantitatively whether the values of one factor are collectively on average larger than the values of another factor.

To analyze the distribution of the data, two main descriptive methods were used to assess normality. First, the mean and median values of the factors were compared to determine if there was any significant deviation of the median from the mean. Second, the skewess statistic was used following the protocol outlined by Morgan et al. (2013): a) if the absolute value of the skewness statistic is less than one, then the distribution is considered to be approximately normal; b) if the skewness statistic is less than twice the standard error, then the distribution is considered to be approximately normal. This data is summarized in Appendix B.

Kruskal-Wallis (K-W) and Mann-Whitney U (M-W) non-parametric tests were selected for the analysis. These tests were most appropriate because the data was found to be non-normally distributed and the underlining assumptions of the tests were not markedly violated (i.e., data is independent and has continuity in the dependent variable). K-W tests were first performed to identify the existence of statistically significant differences in the mean ranks among each factor. A K-W test is described by the Chi-square (χ^2) statistic and a significance level, p (Morgan et al., 2013). The test was taken to be statistically significant when $p<0.05$. The K-W test is capable of analyzing three or more variables simultaneously, although it is incapable of identifying explicitly where the difference exists. The test therefore was used to provide an efficient way of determining whether further analyses were required.

Given a statistically significant difference by a K-W test, a series of M-W tests were performed to identify where exactly a difference existed. The results of a M-W test are described by the Mann-Whitney U (or simply "U"), a z score and a significance level, p (Morgan et al., 2013). The M-W test was taken to be statistically significant when $p<0.05$.

4 RESULTS

This Section provides a summary of results for drilling activity, leakage reports and statistically significant differences in the occurrence of leakage problems among the factors; the results themselves are compiled in Appendices C−E.

4.1 Well Design

4.1.1 Drilling Activity

Across Alberta, the orientation of energy wellbores is either vertical, deviated (i.e., deliberately at an angle of $\sim$10-80^o) or horizontal. In vertical wellbores, the total well depth is equal to the true vertical depth (TVD). Deviated wellbores have a total well depth that is greater than the TVD. Horizontal wellbores are initially drilled vertically or at an angle of inclination, but deviate to become horizontal within the last few hundred meters before the target formation is reached and then drilled horizontally along the target formation.

During the study period, most (62%) wellbores drilled were vertical (Table 4.1). Deviated wellbores were the second most common wellbore (23%) followed by horizontal wells (15%). As illustrated in Figure 4.1, wellbores drilled at the beginning of the study period were predominately drilled vertically; however, by the end of the study period, nearly equal proportions of vertical and non-vertical wellbores were drilled annually.

4.1.2 Occurrence of Leakage Problems

Overall A comparison of deviated to vertical wellbores found that deviated wellbores have a higher total number of reported leakage problems (Table 4.1). A mean comparison test indicates that the mean rank of deviated wellbores (3,695.89, n=2,944) is statistically greater than vertical wellbores (3,503.40, n=4,220), z=-5.36, p=0.00[2]. Earlier literature has also noted that the occurrence of leakage problems is higher in deviated wellbores compared to vertical wells (Watson and Bachu, 2009).

A comparison of horizontal to vertical wellbores found that vertical wellbores have a higher total number of reported leakage problems. Despite the fact that vertical wellbores have a higher total number of reported leakage problems, a mean comparison test indicates that the mean

[2]Since p<0.05, this means that a mean rank of 3,695.89 with a sample size of 2,944 is statistically greater than a mean rank of 3,503.40 with a sample size of 4,220.

Table 4.1. Summary of drilling activity, leakage occurrence and statistically significant differences in the mean proportion of wellbores with leakage problems among vertical (V), horizontal (H) and deviated (D) wells with respect to all wellbores, drilling contractor, well type and reported drilling issues.

Factor		Total Number Drilled (greatest to least)	Total Number Leak (greatest to least)	Significant Differences Occurrence
Overall		V,D,H	D,V,H	D>V H>V
Drilling Contractor	A	V,D,H	D,V,H	D>V H>V
	B	V,D,H	V,D,H	
	C	V,D,H	D,V,H	D>V H>V
	D	D,V,H	D,H,V	D>V H>V
	E	V,H,D	V,H,D	
Well Type	Gas	V,D,H	V,D,H	
	Crude Bitumen	V,D,H	D,V,H	D>V,H H>V
	Crude Oil	D,H,V	D,H,V	D>V H>V
Drilling Issues	Yes	V,D,H	D,V,H	D>V H>V
	No	H,D,V	D,H,V	D>V H>V

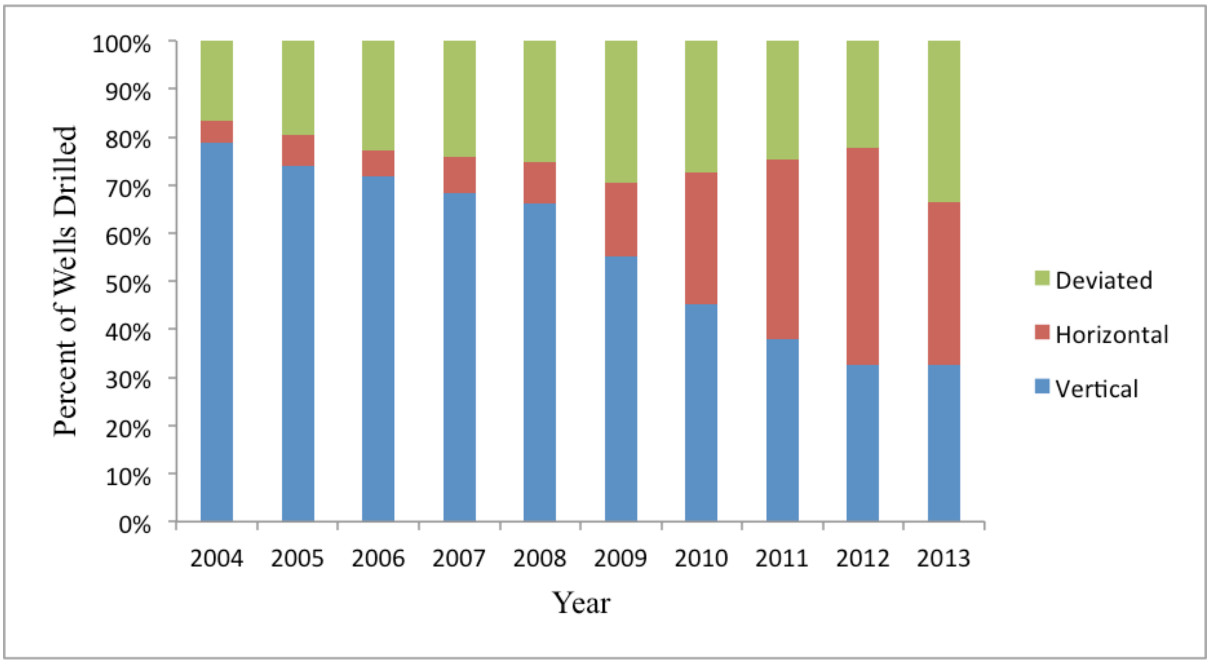

Figure 4.1. Proportion of wellbores spud by orientation per year across Alberta during the study period.

rank of horizontal wellbores (3,024.29, n=1,687) is statistically greater than vertical wellbores (2,925.90, n=4,220), z=-2.82, p=0.01. This indicates that non-vertical wellbores have a higher average occurrence rate of leakage problems than vertical wellbores.

A comparison of deviated to horizontal wellbores found a higher total number of reported leakage problems among deviated wellbores. However, a mean comparison test indicates that the difference in the mean rank of deviated (2,330.88, n=2,944) and horizontal (2,290.03, n=1,687) wellbores is statistically insignificant, z=-1.35, p=0.18. This indicates that although deviated wellbores have a higher total number of reported leakage problems, deviated wellbores are not statistically more prone to leakage problems.

The time of leakage reporting was consistent among each well design (Figure 4.2). Regardless of whether the wellbore was vertical, horizontal or deviated, most leakage problems were reported during the operational life of the wellbore (58%, 66% and 63%, respectively). Between 28% and 32% of leakage problems were reported within 90 days of drill rig release, the time after drilling and completion (perforating, fracturing and acidizing), but before full production. Few leakage problems were reported prior to drill rig release (0.5% – 3%), i.e., before finishing drilling and completion of the wellbore, or after final abandonment among each well design (0.2% – 2%).

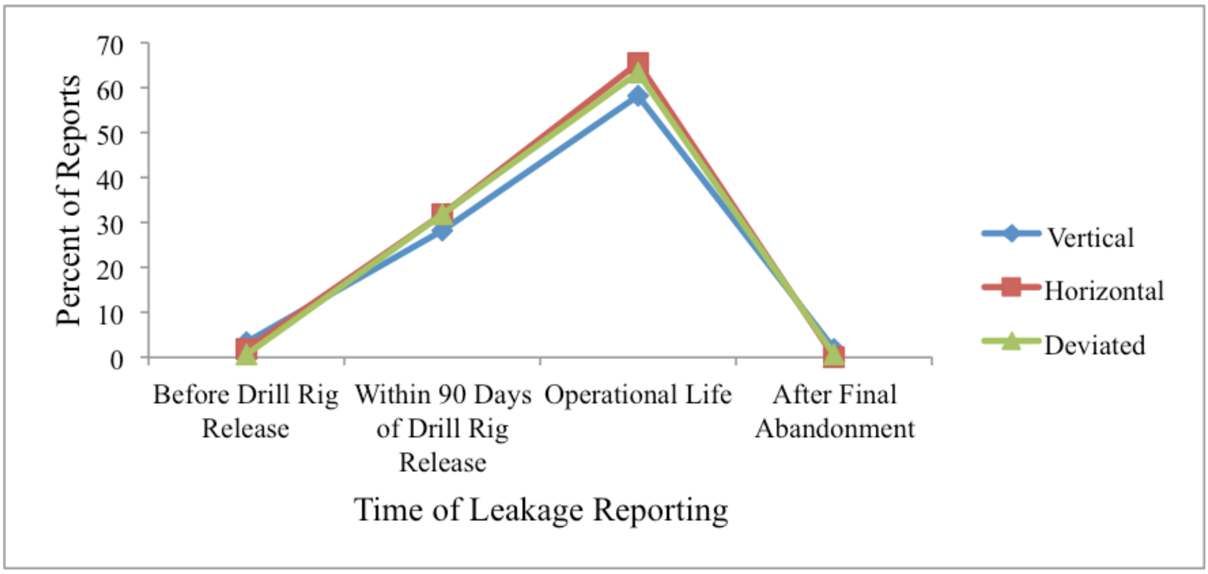

Figure 4.2. Time of leakage reporting for all vertical, horizontal and deviated wellbores.

Evaluation of the Effect of Well Type Among gas wellbores, a comparison of vertical, horizontal and deviated wellbores found the highest total number of reported leakage problems among vertical wellbores. A mean comparison test indicates that the mean rank of each well design is statistically insignificant, $\chi^2(2, N=6{,}180)=3.49$, $p=0.18$[3]. Thus, although there are differences in the total number of reported leakage problems, there is not a particularly problematic well design issue for among gas wells. This finding appears to suggest that deviated gas wellbores are not more prone to leakage problems than wellbores of other orientations.

Among crude bitumen wellbores, a comparison of each well design found the highest total number of reported leakage problems among deviated wellbores. The mean rank of deviated wellbores is statistically greater than both vertical and horizontal wellbores (z=-10.12, p=0.00; z=-2.94, p=0.00, respectively). Furthermore, the average occurrence rate of leakage problems among horizontal wellbores (453.67, n=142) is statistically greater than vertical wellbores (398.36, n=673), z=-4.59, p=0.00. These results indicate that there are notable differences in the occurrence of leakage problems among crude bitumen wellbores depending on the design of the wellbore.

Similarly among crude oil wellbores, the highest total number of reported leakage problems is found in deviated wellbores. Mean comparison tests indicate that the mean rank of deviated wellbores (1,341.95, n=1,124) is statistically greater than vertical wellbores (1,256.25, n=1,462),

[3] Since $p>0.05$, the mean ranks of vertical, deviated and horizontal gas wellbores with two-degrees of freedom and a combined sample size of 6,180 is statistically insignificant.

z=-4.25, p=0.00. The mean rank of horizontal wellbores (1,209.67, n=902) is also statistically greater than vertical wellbores (1,165.74, n=1,462), z=-2.30, p=0.02. There is not a statistically significant difference between the mean ranks of deviated (1,027.38, n=1,124) and horizontal (996.20, n=902) crude oil wellbores, z=-1.67, p=0.10. Hence, non-vertical crude oil wellbores are statistically more prone to leakage problems than vertical crude oil wellbores.

Evaluation of the Effect of Drilling Contractor The highest total number of reported leakage problems corresponds to deviated wellbores among wellbores drilled by Contractors A, C and D. Among wellbores drilled by these Contractors, the mean rank of deviated wellbores is statistically greater than vertical wellbores, z=-7.46, p=0.00; z=-5.46, p=0.00; z=-3.70, p=0.00, respectively. Furthermore, the mean rank of horizontal wellbores drilled by Contractors A, C and D is statistically greater than vertical wellbores, z=-4.13, p=0.00; z=-5.32, p=0.00; z=-2.48, p=0.01. These results indicate that non-vertical wellbores are more prone to leakage problems than vertical wellbores among wellbores drilled by most of the Major Drilling Contractors.

Among wellbores drilled by Contractors B and E, a comparison of each well design found that vertical wellbores have the highest total number of reported leakage problems. A mean comparison test indicated that the mean rank of each well design drilled by these Contractors is statistically insignificant, $\chi^2(2, N=1{,}406)=1.64$, p=0.44 and $\chi^2(2, N=2{,}025)=4.33$, p=0.12, respectively. Thus, although there are differences in the total number of reported leakage problems, there is not a particularly problematic well design among wellbores drilled by these Contractors. These results appear to suggest that deviated wellbores drilled by particular contractors are not prone to leakage problems relative to wellbores of other orientation.

Evaluation of the Effect of Drilling Issues Among wellbores with reported drilling issues, a comparison of each well design found that deviated wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that the mean rank of deviated wellbores (1,477.97, n=1,066) is statistically greater than vertical wellbores (1,382.68, n=1,770), z=-5.92, p=0.00. Furthermore, the mean rank of horizontal wellbores (1,154.28; n=476) is statistically greater than vertical wellbores (1,115.22, n=1,770), z=-2.53, p=0.01. These findings indicate that non-vertical wellbores with reported drilling issues are more prone to leakage problems than vertical wellbores with reported drilling issues.

Among wellbores that did not have a reported drilling issue, a comparison of each well design found that deviated wellbores have the highest total number of reported leakage problems. Further analyses reveal that the mean rank of deviated wellbores (1,015.40, n=872) is statistically greater than vertical wellbores (950.67, n=1,086), z=-3.83, p=0.00. There is also a statistically significant difference in the mean ranks of horizontal (1,003.31, n=883) and vertical (970.11, n=1,086) wellbores, z=-2.01, p=0.04. These results indicate that non-vertical wellbores without reported drilling issues are more prone to leakage problems than vertical wellbores without reported drilling issues.

4.2 Well Type

4.2.1 Drilling Activity

Gas, crude bitumen and crude oil are the most common energy wellbores drilled across Alberta. During the study period, approximately 46% of all energy wellbores were licensed to produce gas, whereas about 25% and 16% were licensed to produce crude bitumen and crude oil, respectively (Table 4.2). Other well types, including coalbed methane, water, "undesignated", brine, miscellaneous, waste, liquid petroleum gas and sand wells, represent about 13% of wellbores drilled during the study period (Figure 4.3).

4.2.2 Occurrence of Leakage Problems

Overall A comparison of gas to crude bitumen wellbores found a higher total number of reported leakage problems among crude bitumen wellbores (Table 4.2). A mean comparison test indicates that the mean rank of gas wellbores (2,262.78, n=3,786) is statistically greater than crude bitumen wellbores (2,145.93, n=702), z=-3.10, p=0.00. These findings indicate that although gas wellbores have a lower total number of reported leakage problems than crude bitumen wellbores, gas wellbores are on average more prone to leakage problems. Watson and Bachu (2009) found no relationship between well-operational mode and the development of wellbore leakage, despite their expectations.

A comparison of crude bitumen to crude oil wellbores found a higher total number of reported leakage problems among crude bitumen wellbores. A mean comparison test indicates that the mean rank of crude oil wellbores (1,350.96, n=1,930) is statistically greater than crude bitumen wellbores (1,221.75, n=702), z=-5.24, p=0.00. Thus, the results appear to show that

Table 4.2. Summary of drilling activity, leakage occurrence and statistically significant differences in the mean proportion of wellbores with leakage problems among gas (G), crude bitumen (B) and crude oil (O) wells with respect to all wellbores, drilling contractor, well design and reported drilling issues.

Factor		Total Number Drilled (greatest to least)	Total Number Leak (greatest to least)	Significant Differences Occurrence
Overall		G,B,O	B,O,G	O>G,B G>B
Drilling Contractor	A	G,B,O	B,O,G	B>G O>G
	B	G,B,O	G,O,B	B>G O>G
	C	G,O,B	O,G,B	O>G,B
	D	B,G,O	B,O,G	B>O,G
	E	B,G,O	G,O,B	
Well Design	Vertical	G,B,O	G,O,B	O>B G>B
	Horizontal	O,B,G	O,B,G	B>G O>G
	Deviated	G,B,O	B,O,G	B>O,G O>G
Drilling Issues	Yes	G,O,B	G,O,B	
	No	O,B,G	B,O,G	B>G O>G

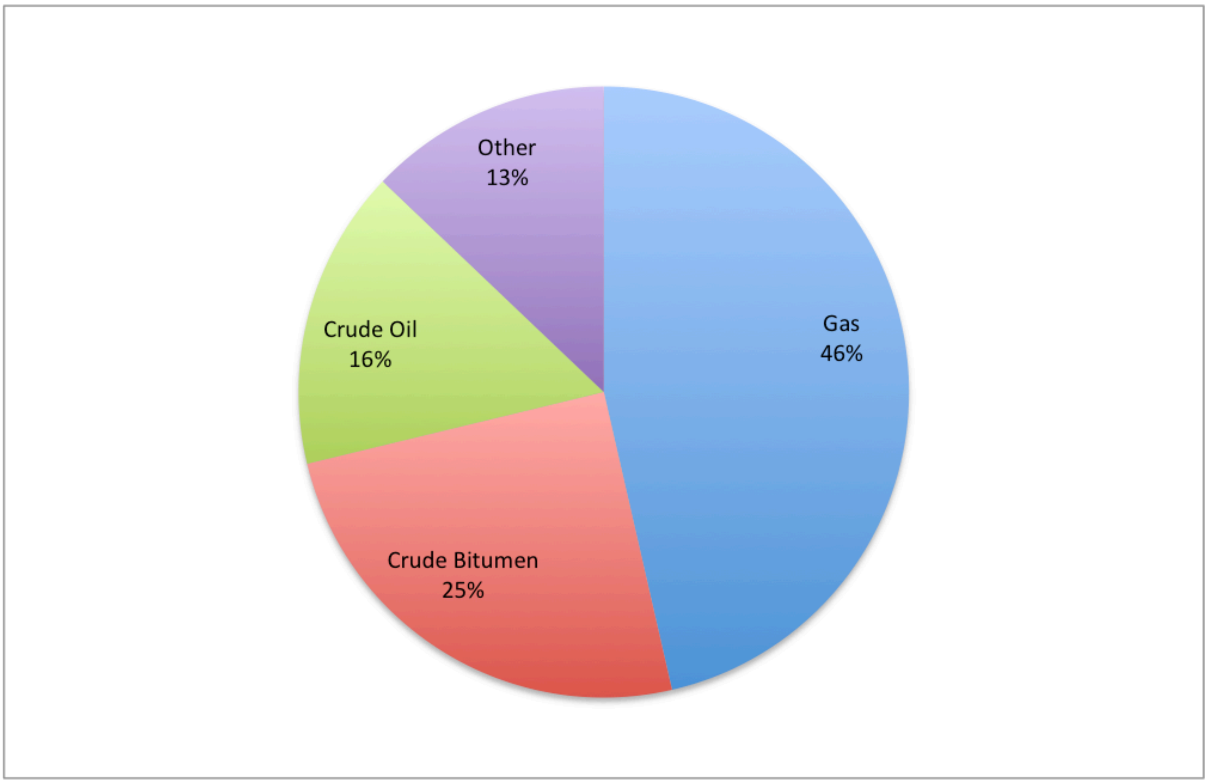

Figure 4.3. Proportion of wellbores spud by type during the study period. Most wellbores were licensed to produce gas, crude bitumen and crude oil. Other types of wellbores (e.g., water, coalbed methane, liquid petroleum gas, etc.) were less common and therefore were not the focus of this study.

crude bitumen wellbores have a higher total number of reported leakage problems than gas and crude bitumen wellbores, but crude bitumen wellbores are on average the least prone to leakage problems.

Crude oil wellbores have a greater total number of reported leakage problems than gas wellbores. A mean comparison test indicates that the average occurrence rate of leakage problems is statistically higher among crude oil wellbores (2,954.99, n=1,930) in comparison to gas wellbores (2,809.31, n=3,786), z=-4.30, p=0.00. These results indicate that crude oil wellbores are more problematic than gas wellbores.

The time of leakage reporting was similar among each well type (Figure 4.4). Most leakage problems among gas, crude bitumen and crude oil wellbores were reported during the operational life of the wellbore (62%, 66%, and 55%, respectively). Between 25% and 40% of leakage problems were reported within 90 days of drill rig release. Few leakage problems were reported prior to drill rig release (0% – 2%) or after final abandonment among each well type (0.7% – 1%).

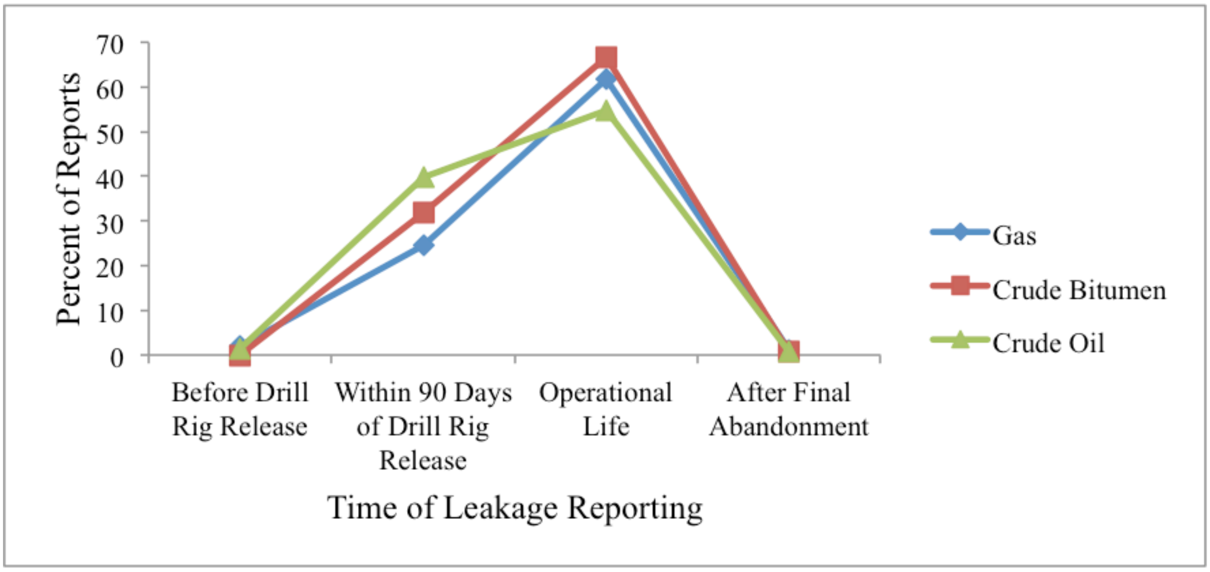

Figure 4.4. Time of leakage reporting for all gas, crude bitumen and crude oil wellbores.

Evaluation of the Effect of Well Design Among vertical wellbores, a comparison of gas, crude bitumen and crude oil wellbores found that gas wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that the mean rank of gas wellbores (2,129.14, n=3,541) is statistically greater than crude bitumen wellbores (1,993.62, n=673), z=-4.31, p=0.00. Furthermore, the mean rank of crude oil wellbores (1,092.06, n=1,462) is statistically greater than crude bitumen wellbores (1,015.74, n=673), z=-4.43, p=0.00. These results indicate that among vertical wellbores, there are notable differences in the occurrences of leakage problems between each well type.

Among horizontal wellbores, a comparison of each well type found that crude oil wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that the mean rank of crude oil wellbores (723.45, n=902) is statistically greater than gas wellbores (686.54, n=517), z=-2.44, p=0.02. There is also a statistically significant difference in the mean ranks of crude bitumen (350.39, n=142) and gas (324.40, n=517) wellbores, z=-2.25, p=0.02. These results appear to suggest that horizontal crude oil and crude bitumen wellbores are more prone to leakage problems than horizontal gas wellbores.

Among deviated wellbores, crude bitumen wellbores have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of crude bitumen wellbores is statistically greater than both crude oil and gas wellbores, z=-4.30, p=0.00 and z=-7.32, p=0.00, respectively. Furthermore, the mean rank of crude oil wellbores (1,686.71,

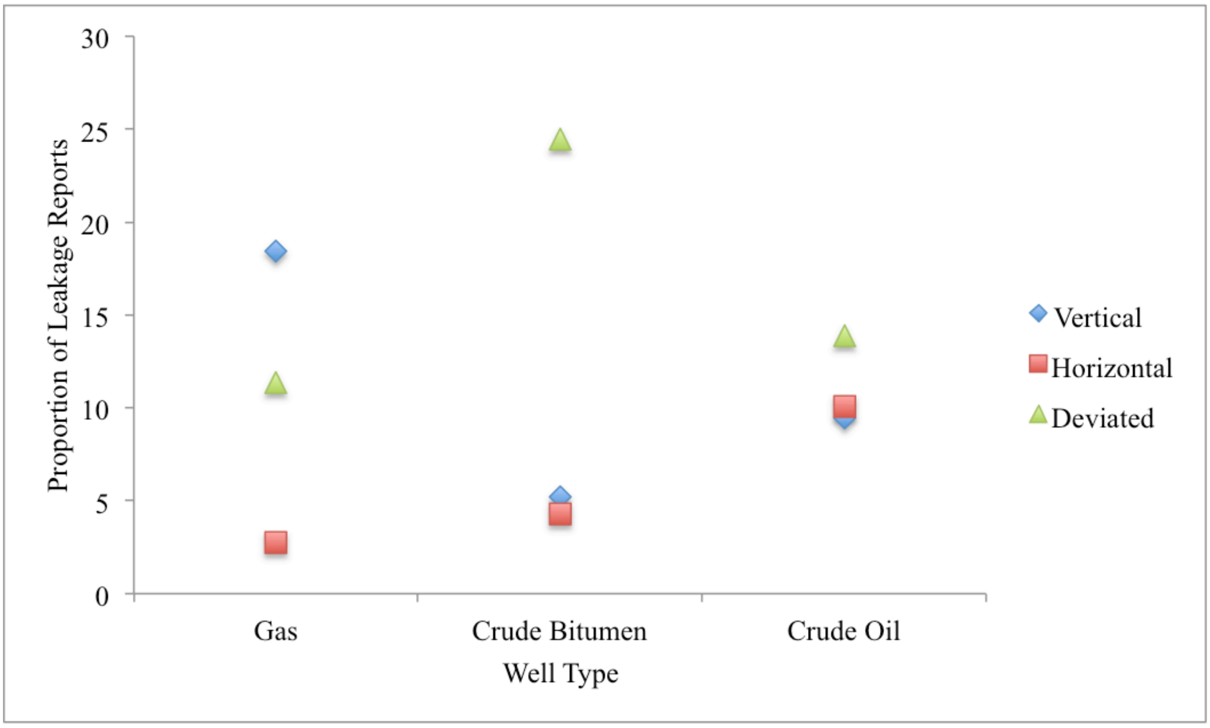

Figure 4.5. Proportion of leakage reports corresponding to gas, crude bitumen and crude oil wellbores of each orientation.

n=1,124) is statistically greater than gas wellbores (1,590.02, *n*=2,122), *z*=-4.12, *p*=0.00. This indicates that deviated crude bitumen wellbores are more prone to leakage problems than deviated wellbores of any other type. Deviated crude oil wellbores are also more prone to leakage problems than deviated gas wellbores.

Overall, well design has a strong relationship with the occurrence of leakage problems among each well type. As shown in Figure 4.5, the highest proportion of leakage reports generally corresponds to deviated wellbores regardless of well type, followed by vertical and horizontal wellbores. Thus, it appears that the design of the well has a stronger relationship on the development of leakage problems than what the wellbore is licensed to produce.

Evaluation of the Effect of Drilling Contractor The highest total number of reported leakage problems corresponds to crude bitumen wellbores among wellbores drilled by Contractors A and D. Among wellbores drilled by both of these Contractors, a mean comparison test indicates that the mean rank of crude bitumen wellbores is statistically greater than gas wellbores (*z*=-5.74, *p*=0.00 and *z*=-5.76, *p*=0.00, respectively). There is also a statistically significant difference in the mean ranks of crude oil (1,755.17, *n*=1,024) and gas (1,630.85, *n*=2,313) wellbores among wellbores drilled by Contractor A, *z*=-5.67, *p*=0.00.

Among wellbores drilled by Contractors B and E, the highest total number of reported leakage problems corresponds to gas wellbores. Among wellbores drilled by Contractor B, the mean rank of crude bitumen wellbores (522.70, n=81) is statistically greater than gas wellbores (496.45, n=920), z=-3.70, p=0.00. There is also a statistically significant difference in the mean rank of crude oil (597.12, n=133) and gas (516.86, n=920) wellbores among wellbores drilled by this Contractor, z=-5.93, p=0.00. Among wellbores drilled by Contractor E, a mean comparison test indicates that the difference in mean rank among gas, crude bitumen and crude oil wellbores is statistically insignificant, χ^2(2, N=1,465)=4.29, p=0.12.

Among wellbores drilled by Contractor C, crude oil wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that the mean rank of crude oil wellbores is statistically greater than both gas and crude bitumen wellbores, z=-6.90, p=0.00 and z=-4.34, p=0.00, respectively.

Evaluation of the Effect of Drilling Issues Among wellbores with reported drilling issues, gas wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that there is not a statistically significant difference between the mean ranks of gas, crude bitumen and crude oil wellbores, χ^2(2, N=2,403)=1.32, p=0.52. These results indicate that neither gas, crude bitumen or crude oil wellbores are more prone to leakage problems among those wellbores with reported drilling issues.

Among wellbores without reported drilling issues, crude bitumen wellbores have the highest total number of reported leakage problems. A mean comparison test indicates that the mean rank of crude bitumen wellbores (587.39, n=217) is statistically greater than gas wellbores (522.94, n=854), z=-4.22, p=0.00. Furthermore, there is a statistically significant difference in the mean ranks of crude oil (880.86, n=852) and gas (826.20, n=854) wellbores, z=-3.46, p=0.00. These findings indicate that there are differences in the occurrence of leakage problems between each well type among those wellbores without reported drilling issues.

4.3 Drilling Contractor

4.3.1 Drilling Activity

In excess of 137,000 energy wellbores were spud across Alberta during between 2004 and 2013 by a total of 530 drilling contractors. The total number of wellbores drilled by each con-

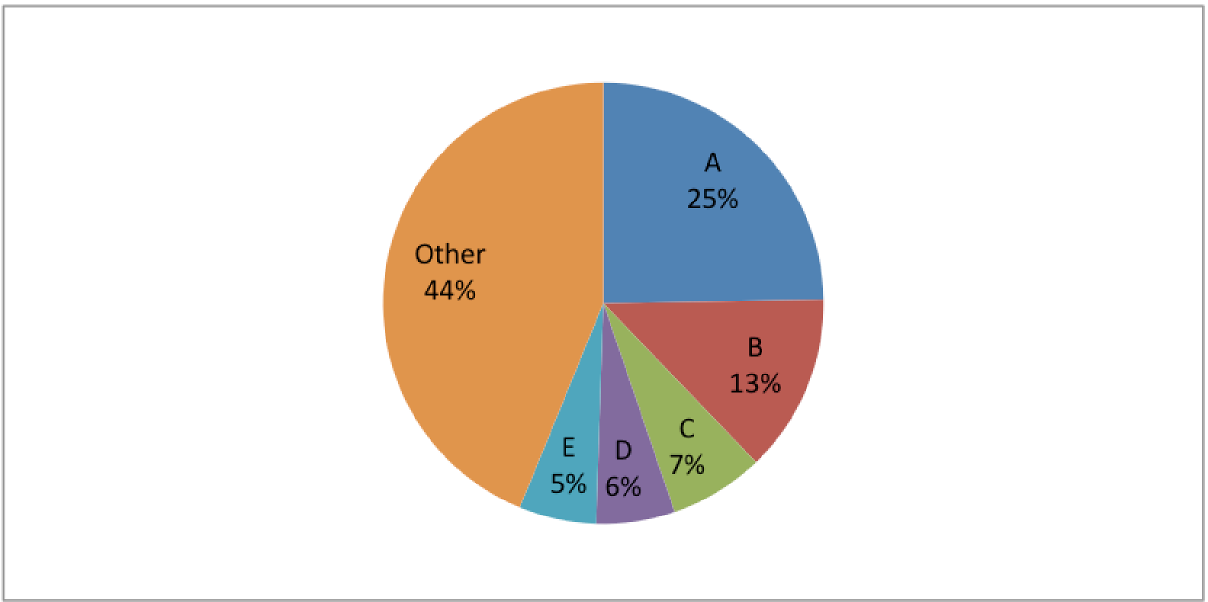

Figure 4.6. Proportion of wellbores spud by the Major Drilling Contractors (Contractors A through E) during the study period. The Major Drilling Contractors cumulatively drilled over half of all wellbores in Alberta. Other drilling contractors (total of 525 contractors) drilled far fewer wellbores and therefore were not the focus of this study.

tractor was significantly variable, ranging from a single wellbore to nearly 34,000 wellbores. As shown in Figure 4.6, cumulatively over half (56%) of the wellbores spud were drilled by five contractors, i.e., the Major Drilling Contractors. With respect to the total number of wellbores spud during the study period, 25%, 13%, 7%, 6% and 5% corresponded to wellbores drilled by Contractors A, B, C, D and E, respectively (Table 4.3).

4.3.2 Occurrence of Leakage Problems

Overall A comparison of the total number of reported leakage problems among wellbores drilled by the Major Drilling Contractors found that wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors B, C, D and E, z=-7.02, p=0.00; z=-6.17, p=0.00; z=-4.03, p=0.00; and z=-6.47, p=0.00, respectively. These findings indicate that wellbores drilled by Contractor A are more prone to leakage problems than wellbores drilled by the other Major Drilling Contractors.

Wellbores drilled by Contractor D have the second highest total number of reported leakage problems among wellbores drilled by the Major Drilling Contractors. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor D (1,259.40, n=1,329) is statistically greater than wellbores drilled by Contractor B (1,214.28, n=1,147), z=-2.82, p=0.02. Thus,

Table 4.3. Summary of drilling activity, leakage occurrence and statistically significant differences in the mean proportion of wellbores with leakage problems among wellbores drilled by the Major Drilling Contractors with respect to all wellbores, well design, well type and reported drilling issues.

Factor		Total Number Drilled (greatest to least)	Total Number Leak (greatest to least)	Significant Differences Occurrence
Overall		A,B,C,D,E	A,D,C,E,B	A>B,C,D,E D>B
Well Type	Gas	A,B,C,E,D	A,C,E,D,B	A>B,C,D,E
	Crude Bitumen	A,D,E,C,B	A,D,B,E,C	A>C,E B>C,E D>C,E
	Crude Oil	A,C,E,D,B	A,C,E,D,B	A>D,E B>D,E C>D,E
Well Design	Vertical	A,B,C,E,D	A,B,C,D,E	A>B,C,D,E
	Horizontal	A,D,E,C,B	A,D,E,C,B	C>D,E
	Deviated	A,D,C,B,E	A,D,C,E,B	A>B,D,E C>E D>E
Drilling Issues	Yes	A,B,D,E,C	A,D,C,E,B	A>B C>B D>B,E
	No	A,D,E,B,C	A,D,C,E,B	A>B C>B D>B

wellbores drilled by Contractor D are more prone to leakage problems than wellbores drilled by Contractor B.

The time of leakage reporting among wellbores drilled by the Major Drilling Contractors was similar. Most leakage problems were reported during the operational life of the wellbore (A: 60%, B: 54%, C: 56%, D: 68%, E: 57%). Between 26% and 41% of leakage problems were reported within 90 days of drill rig release. Few problems were reported before drill rig release (0.3% – 1%) or after final abandonment (0% – 4%) (Figure 4.7).

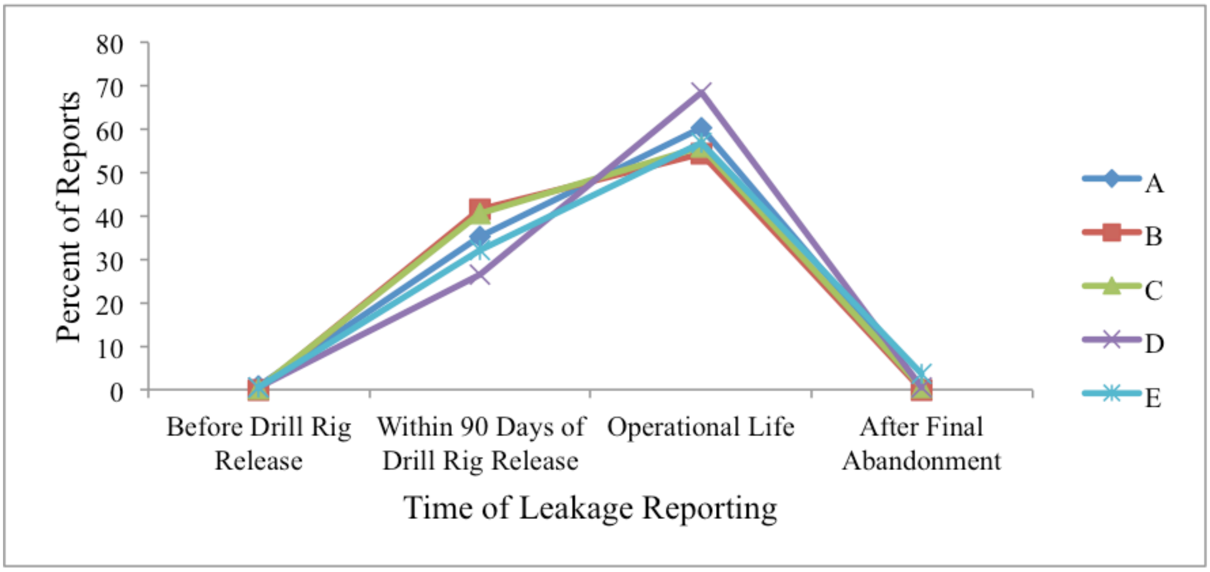

Figure 4.7. Time of leakage reporting for all wellbores drilled by the Major Drilling Contractors.

Evaluation of the Effect of Well Design Among vertical wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors B, C, D and E, z=-2.06, p=0.04; z=-3.75, p=0.00; z=-2.16, p=0.03; and z=-2.14, p=0.03, respectively. These results indicate that vertical wellbores drilled by Contractor A are more prone to leakage problems than vertical wellbores drilled by any other Major Drilling Contractor.

Among horizontal wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically insignificant compared to wellbores drilled by the other Major Drilling Contractors. There are statistically significant differences in the mean ranks of wellbores drilled by Contractor C in comparison to wellbores drilled by Contractors D and E, z=-2.19, p=0.03 and z=-2.31, p=0.02, respectively. These findings indicate that although wellbores drilled by Contractor A have the highest total number of reported leakage problems, these wellbores on average are not more prone to leakage problems than horizontal wellbores drilled by the other Major Drilling Contractors. Horizontal wellbores drilled by Contractor C are more prone to leakage problems than horizontal wellbores drilled by Contractors D and E.

Among deviated wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors B, D and E, z=-3.44, p=0.00, z=-2.36, p=0.02 and z=-5.96, p=0.00, respectively. Wellbores drilled by Contractors C and D also have a statistically greater mean rank than wellbores drilled by Contractor E, z=-3.61, p=0.00 and z=-3.25, p=0.00, respectively. Hence, deviated wellbores drilled by Contractor A are more prone to leakage problems than deviated wellbores drilled by most of the other Major Drilling Contractors. Also, deviated wellbores drilled by Contractors C and D are more prone to leakage problems than deviated wellbores drilled by Contractor E.

Evaluation of the Effect of Well Type Among gas wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors B, C, D and E, z=-4.63, p=0.00; z=-4.31, p=0.00; z=-2.34, p=0.02; z=-2.26, p=0.02, respectively. Thus, gas wellbores drilled by Contractor A are on average more prone to leakage problems than gas wellbores drilled by any of the other Major Drilling Contractors.

Among crude bitumen wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors C and E, z=-5.11, p=0.00 and z=-4.67, p=0.00, respectively. Furthermore among crude bitumen wellbores, wellbores drilled by Contractor D have the second highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor D is statistically greater than wellbores drilled by Contractors C and E, z=-5.03, p=0.00 and z=-4.51, p=0.00, respectively. Also among crude bitumen wellbores, wellbores drilled by Contractor B have a higher total number of reported leakage problems than wellbores drilled by Contractors C and E, despite the fact that Contractor B drilled fewer crude bitumen wellbores. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor B is statistically greater than wellbores drilled by Contractors C and E, z=-3.47, p=0.00 and z=-2.54, p=0.01, respectively. These results indicate that crude bitumen wellbores drilled by Contractors A, D and B are on average more prone to leakage problems than crude bitumen wellbores drilled by Contractors C and E.

Among crude oil wellbores, wellbores drilled by Contractor A have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractor A is statistically greater than wellbores drilled by Contractors D and E, z=-3.40, p=0.00 and z=-3.11, p=0.00, respectively. Also among crude oil wellbores, wellbores drilled by Contractor C have the second highest total number of reported leakage problems. Mean comparison tests indicated that the mean rank of wellbores drilled by Contractor C is statistically greater than wellbores drilled by Contractors D and E, z=-3.06, p=0.00 and z=-2.85, p=0.00, respectively. The mean rank of crude oil wellbores drilled by Contractor B is also statistically greater than wellbores drilled by Contractors D and E, z=-2.91, p=0.00 and z=-2.79, p=0.01, respectively; however, crude oil wellbores drilled by Contractors D and E have a greater total number of reported leakage problems. These findings indicate that crude oil wellbores drilled by Contractors A, B and C are more prone to leakage problems than crude oil wellbores drilled by Contractors D and E.

Evaluation of the Effect of Drilling Issues Among wellbores with reported drilling issues, wellbores drilled by Contractors A, D and C have the highest total number of reported leakage problems, respectively. Mean comparison tests indicate that the mean rank of wellbores drilled by Contractors A, D and C is statistically greater than wellbores drilled by Contractor B, z=-3.61, p=0.00; z=-3.77, p=0.00; and z=-3.08, p=0.00, respectively. The mean rank of wellbores drilled by Contractor D is also statistically greater than wellbores drilled by Contractor E, z=-2.07, p=0.04. Thus among wellbores with reported drilling issues, there are differences in the average occurrence of leakage problems among wellbores drilled by a particular drilling contractor.

Among wellbores without reported drilling issues, wellbores drilled by Contractors A, D and C have the highest total number of reported leakage problems. Mean comparison tests indicate that the mean ranks of wellbores drilled by Contractors A, D and C are statistically

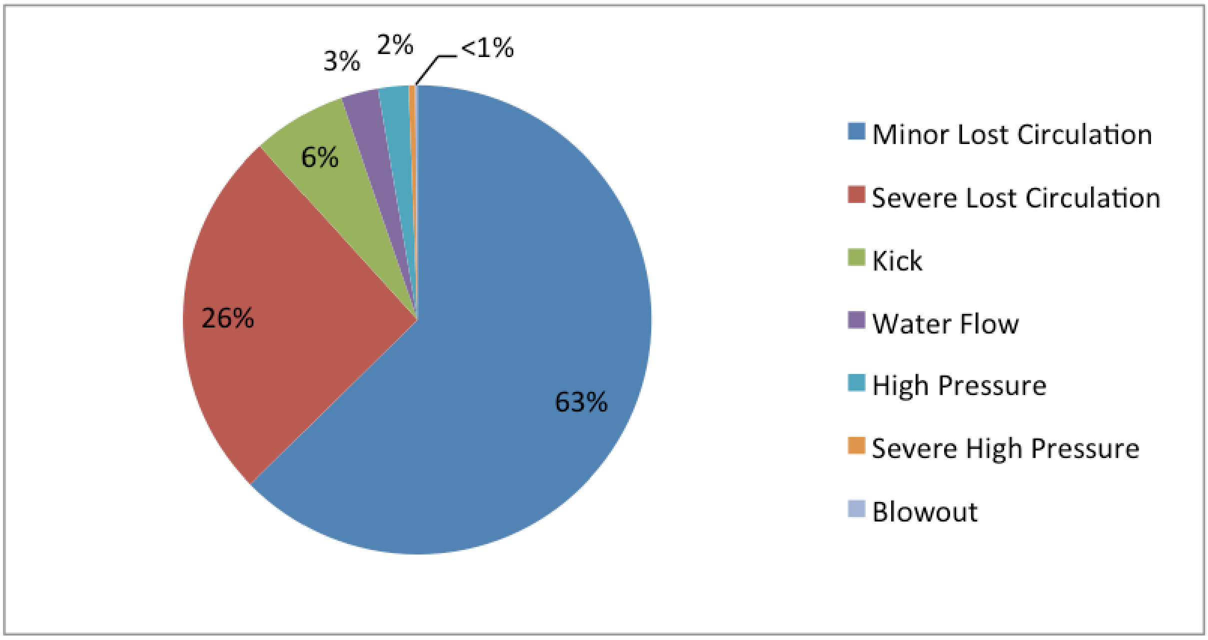

Figure 4.8. Drilling issues reported among wellbores spud during the study period in Alberta.

greater than wellbores drilled by Contractor B, z=-3.27, p=0.00; z=-3.07, p=0.00; and z=-3.22, p=0.00, respectively. These findings indicate that among wellbores without reported drilling issues, there are differences in the average occurrence of leakage problems among wellbores drilled by a particular drilling contractor.

4.4 Drilling Issues

4.4.1 Drilling Activity

Drilling issues are unforeseeable challenges that are encountered during the drilling of energy wellbores. The most common drilling issue reported in Alberta is lost circulation, a problem where drilling fluid flows uncontrollably into an adjacent permeable formation such as a fault, fracture, or cavernous carbonate zone (Aldred et al., 1999) (Figure 4.8). Most lost circulation problems are minor with partial drilling fluid loss. More serious lost circulation problems may result in total mud loss with no return at the surface. Kicks and blowouts are also drilling issues that have been reported in Alberta. A kick is the forced fluid flow from the formation rock into the wellbore. Kicks occur when a high pressure formation is encountered and the pressure of the formation fluid is greater than the hydrostatic pressure of the drilling fluid. In more serious cases when the kick cannot be controlled, a blowout may occur.

Among wellbores spud across Alberta during the study period, approximately 83% of wellbores did not indicate whether there was an issue encountered during the drilling of the wellbore. Considering only wellbores where a report was completed (total of 23,286 wellbores), the majority (62%) indicated that there was not an issue encountered (Table 4.4).

4.4.2 Occurrence of Leakage Problems

Overall A comparison of wellbores with reported drilling issues to wellbores without reported drilling issues found a higher total number of reported leakage problems among wellbores without reported drilling issues. A mean comparison test indicates that the average occurrence rate of leakage problems among wellbores without reported drilling issues is statistically greater than wellbores that did have reported a drilling issue, z=-7.53, p=0.00. This finding indicates that wellbores that did not have a reported drilling issue are more prone to leakage problems than wellbores that did have a reported drilling issue.

The time of leakage reporting was similar among wellbores regardless of whether there was a reported drilling issue (Figure 4.9). Most leakage problems among wellbores with and without reported drilling issues were reported during the operational life of the wellbore (61% and 56%, respectively). Between 31% and 36% of leakage problems were reported within 90 days of drill rig release. Few leakage problems were reported prior to drill rig release (1% – 2%) or after final abandonment (∼1%).

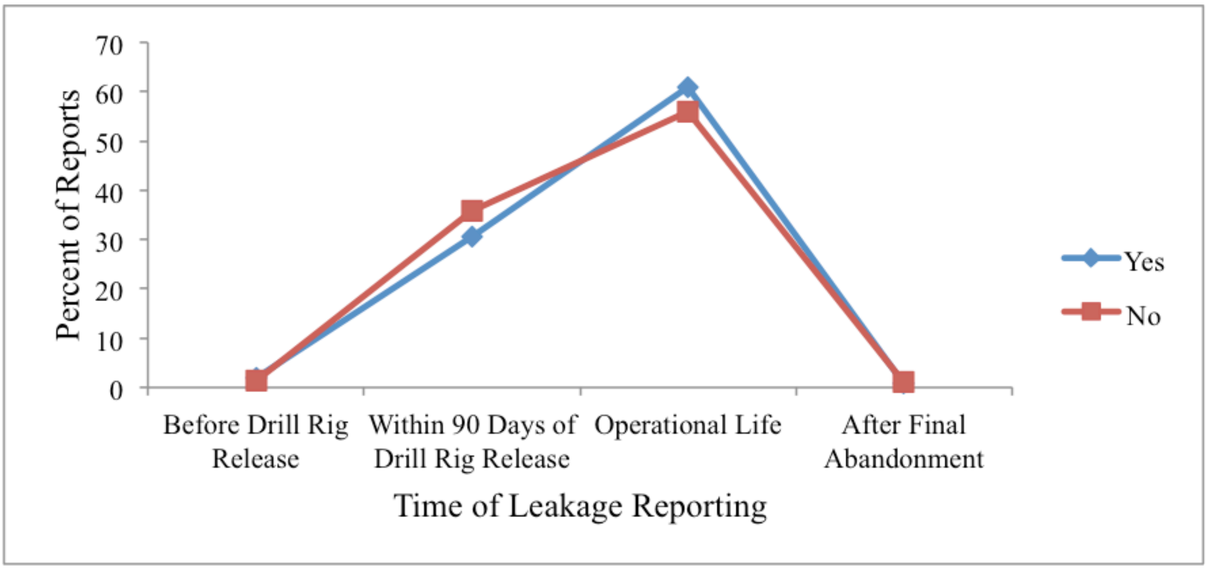

Figure 4.9. Time of leakage reporting for all wellbores with and without reported drilling issues.

Table 4.4. Summary of drilling activity, leakage occurrence and statistically significant differences in the mean proportion of wellbores with leakage problems among wellbores with and without reported drilling issues with respect to all wellbores, drilling contractor, well design and well type.

Factor		Total Number Drilled (greatest to least)	Total Number Leak (greatest to least)	Significant Differences Occurrence
Overall		N,Y	N,Y	N>Y
Drilling Contractor	A	N,Y	N,Y	N>Y
	B	Y,N	N,Y	N>Y
	C	N,Y	N,Y	N>Y
	D	N,Y	N,Y	N>Y
	E	N,Y	N,Y	N>Y
Well Type	Gas	Y,N	Y,N	N>Y
	Crude Bitumen	N,Y	N,Y	N>Y
	Crude Oil	N,Y	N,Y	N>Y
Well Design	Vertical	Y,N	N,Y	N>Y
	Horizontal	N,Y	N,Y	N>Y
	Deviated	N,Y	N,Y	N>Y

Evaluation of the Effect of Well Design Regardless of whether the wellbore was vertical, horizontal or deviated, wellbores without reported drilling issues have a higher total number of reported leakage problems than wellbores with reported drilling issues. Mean comparison tests indicate that the mean rank of wellbores without reported drilling issues is statistically greater than wellbores with reported drilling issues: vertical – z=-6.37, p=0.00; horizontal – z=-3.52, p=0.00; and deviated – z=-4.14, p=0.00. These findings indicate that regardless of well design, wellbores that did not have a reported drilling issue are on average more prone to leakage problems than wellbores with reported drilling issues.

Evaluation of the Effect of Well Type Among crude bitumen and crude oil wellbores, wellbores without reported drilling issues have a higher total number of reported leakage problems than wellbores with reported drilling issues. Mean comparison tests indicate that the mean rank of wellbores without reported drilling issues is statistically greater than wellbores with reported drilling issues, z=-5.34, p=0.00 and z=-4.65, p=0.00, respectively. Thus among crude bitumen and crude oil wellbores, wellbores without reported drilling issues are on average more prone to leakage problems than wellbores with reported drilling issues.

Among gas wellbores, wellbores with reported drilling issues have a greater total number of reported leakage problems than wellbores without reported drilling issues. Mean comparison tests indicate that the mean rank of wellbores without reported drilling issues (1,181.27, n=854) is statistically greater than wellbores with reported drilling issues (1,137.17, n=1,452), z=-2.76, p=0.01. Hence, gas wellbores with reported drilling issues have a greater total number of reported leakage problems than gas wellbores without reported drilling issues, but gas wellbores without reported drilling issues are on average more prone to leakage problems.

Evaluation of the Effect of Drilling Contractor Regardless of the drilling contractor, wellbores without reported drilling issues have a higher total number of reported leakage problems than wellbores with reported drilling issues. Mean comparison tests indicate that the mean ranks of wellbores without reported drilling issues among each Major Drilling Contractor are statistically greater than wellbores with reported drilling issues: A – z=-5.18, p=0.00; B – z=-2.13, p=0.03; C – z=-2.84, p=0.01; D – z=-2.37, p=0.02; and E – z=-2.79, p=0.01. These findings appear to indicate that wellbores without reported drilling issues are on average more prone to leakage problems than wellbores with reported drilling issues regardless of which contractor drilled the wellbore.

5 DISCUSSION AND IMPLICATIONS

5.1 Study Design

Our current understanding of the major factors influencing the occurrence of wellbore leakage is based on the previous work of Watson and Bachu (2009). However, because their study focused on leakage reports from wellbores completed up until 2004 that were primarily conventional wellbores, there is uncertainty as to whether the major leakage factors identified by their study are reflective of leakage problems from more recently drilled wellbores, particularly those that are used for the production of unconventional resources.

To investigate this gap in knowledge, a similar database to Watson and Bachu (2009) was compiled by integrating the AER's SCVF and GM reports with detailed well information with the focus on wellbores spud between 2004 and 2013. Much like the earlier study, the database compiled in this study was data mined to evaluate the influence of several factors on the development of leakage problems. However, there were several changes to the design of this study for the purpose of overcoming challenges and limitations encountered by Watson and Bachu (2009). The changes in the study design are related to time, geographic location, well status and average occurrence rates of leakage problems.

Time Time may influence the development of leakage problems in several ways:

1. Time reflects knowledge availability at the time of construction (Watson and Bachu, 2009; King and King, 2013). In other words, industry best practices are reflective of what was known to be most effective at the time at which the wellbore was constructed. Well construction practices advance over time through a learning-by-doing process, consequently the development of leakage problems is expected to be higher among older wellbores.

2. Natural processes such as material degradation and changing earth stresses acting on wellbores over time can increase the likelihood of leakage problem development (King and King, 2013). Consequently, the development of leakage problems is expected to be higher among older wellbores, which have been exposed to natural conditions and formation fluids for a longer period of time.

3. Wellbores are constructed and abandoned following the regulations at the time of con-

struction and abandonment (Watson and Bachu, 2009). Since regulations have changed over time, more recently drilled wellbores were constructed and abandoned following more stringent regulations. Consequently, the development of leakage problems is expected to be greater among older wellbores constructed during times of more lenient regulations.

Although time is expected to have a significant influence on the development of leakage problems, this factor is often difficult to investigate since regulations regarding wellbore leakage monitoring and reporting have changed through time. In Alberta, wellbore leakage monitoring and reporting requirements were not implemented until 1995 (Watson and Bachu, 2009). Consequently, wellbores drilled and abandoned prior to this date may not have been tested for leakage problems. Therefore a difference in the occurrence rate of leakage problems between newer and older wellbores may be an artifact of varying monitoring and reporting requirements through time.

The challenges of investigating time were encountered by Watson and Bachu (2009). The authors investigated all wellbores spud up until 2004 and therefore the wellbores included in their study spanned several decades in age. In contrast to the authors' expectations, well age was found to have no apparent impact on the development of wellbore leakage. The authors attributed this finding to regulatory changes. Consequently, given the lack of data, Watson and Bachu could not conclude whether well age had an impact on the development of wellbore leakage.

To avoid the challenges of time, this study attempted to control the influence of time by constraining the study to wellbores spud between 2004 and 2013. It was assumed that over a ten-year period that industrial best practices would not have changed significantly and that natural processes would have had minimal impact on the integrity of wellbores. Monitoring and reporting regulations would have also been relatively consistent during this time period. The benefit of controlling the impact of time on the development of leakage problems was to reduce the ambiguity associated with leakage reporting. Furthermore, controlling time provided the opportunity to better understand which wellbores are developing leakage problems in the short-term (i.e., immediately or within a few years of well construction) so that industry and regulators can better understand which wellbores are of immediate concern.

Despite best efforts to remove the influence of time, there remains the possibility that there will be a bias towards some wellbores that have a short life expectancy. Wellbores that were drilled, produced and subsequently abandoned during the study period will have consequently been tested for leakage more than wellbores that remain active to date or that have been in a suspended status for a long time.

Geographic Location Geographic location is a factor that may influence the development of leakage problems for three main reasons:

1. Some areas are found to be more prone to leakage problems than other areas because of more challenging geological conditions in the area. For instance, the presence of shallow gravel beds, swelling clays and thin non-commercial hydrocarbon-bearing formations found in a problematic region of Alberta known as the Test Area (see Section 2.4.1) seems to make obtaining and maintaining an adequate cement seal difficult, to which has been attributed to the high occurrences of leakage problems in the area (Saponja, 1999). Consequently, the development of leakage problems is expected to be higher in areas with the presence of problematic geological formations.

2. Some areas are found to be more prone to leakage problems than other areas because of particular activities occurring in the area. The production of some resources in a particular area requires stress-inducing operations (e.g., enhanced oil recovery operations such as steam-assisted gravity drainage or cyclic steam injection) that may compromise the integrity of a wellbore (see Section 2.6.2). Consequently, the development of leakage problems is expected to be higher in areas that require particular activities that increase the operational stresses on wellbores.

3. Regulations with respect to wellbore leakage monitoring and reporting are variable geographically. In Alberta, the Test Area is a designated problem area that has more stringent monitoring regulations than other areas of the Province (see Section 2.4.1). Within this area, licensees are required to test for GM on all wellbores, whereas outside of the Test Area, licensees are only required to test for SCVF. Consequently, a difference in the occurrence rate of leakage problems between two areas may be an artifact of varying monitoring and reporting requirements in the areas.

Since geographic area can have a significant influence on the development of leakage problems, this factor raises challenges when investigating wellbore leakage problems on a small scale, i.e., a township (36 mi^2 or 93.25 km^2). This is attributed to the fact that any conclusions drawn on a sample of wellbores from one location may not be reflective of leakage problems in other areas of the Province. In other words, small-scale studies may result in a sampling bias for which leakage problems among a subset of wellbores may not be representative of leakage problems as an entirety across Alberta. This study attempted to overcome the issues of geographic location by not focusing on one particular problem area, rather by investigating regional trends. Therefore the results of this study can provide insight as to what wellbores are of greatest concern across the entire Province as a whole. However, this approach is limited by the fact that some potentially problematic areas may be overlooked.

Well Status Watson and Bachu (2009) were mainly interested in the risk presented by abandoned wellbores to carbon dioxide (CO_2) sequestration operations and therefore focused exclusively on wellbores that had been abandoned. This study is interested in understanding the development of leakage problems from wellbores of all statuses and therefore includes leakage reports during the entire lifespan of the wellbore including initial construction, the active operational life and after final abandonment.

Average Occurrence Rates of Leakage Problems Watson and Bachu (2009) performed a correlational study between several factors and the occurrence of leakage problems. Such a study design provides an opportunity to identify any possible relationships that might exist between the factors and the occurrence of leakage problems. However, a correlational study provides no information as to why the total number of reported leakage problems might be higher among a particular group of wellbores relative to another. Furthermore, some important relationships may be overlooked if there is a significant difference in drilling activity (i.e., the total number of wellbores drilled) between two groups of wellbores.

This study therefore investigated drilling activity and average occurrence rates of leakage problems to explain differences in the total number of leakage problems between two groups of wellbores, variously defined. Such distinctions can help industry and regulators identify the wellbores of greatest concern and allow them to make informed predictions on the likelihood of the development of leakage problems with changing drilling activity through time.

5.2 Influence of Factors on the Occurrence of Leakage Problems

5.2.1 Well Design

The finding that most leakage problems among deviated wellbores are reported during the operational life of the wellbore (Section 4.1) has important implications related to the mechanisms responsible for the development of leakage problems. Reports indicate that the problems among deviated wellbores are attributed to poor primary completions, whereby challenges centralizing the casing result in inadequate drilling fluid displacement and subsequent problems placing a cement slurry uniformly around the steel casing strings. This failure to centralize the casing consequently interferes with obtaining a tight initial seal (see Section 2.6.1) (Bellabarba et al., 2008; Roth et al., 2008; Watson and Bachu, 2009; Zhang and Bachu, 2011; Macedo et al., 2012).

The initial testing requirement for wellbore leakage may be insufficient for detecting problems arising as a consequence of poor primary completions. To ensure that a wellbore has sufficient strength and integrity, the Alberta Energy Regulator requires that newly constructed wellbores undergo a series of tests including monitoring for wellbore leakage. By regulation, wellbores must be tested for wellbore leakage within 90 days of drill rig release, i.e., after drilling and completion, but before full production begins. However, leakage problems arising as a consequence of construction challenges may have gone undetected following initial testing. One explanation is that the development of a continuous pathway to the surface is not instantaneous and consequently a leakage problem may take many years after production has ceased before manifesting at the surface. As discussed by Watson and Bachu (2009), leakage problems may be masked by the hydrostatic pressure of drilling fluid residing within a microannular channel, which dissipates over time due to dehydration of mud thus allowing gas to flow. Furthermore, cement shrinkage may lead to differences between lateral stress and fluid pressure gradients, which consequently may result in the formation of microannular spaces that grow vertically over time because of an upward driving displacement pressure generated by gas buoyancy (see Section 2.6.3) (Dusseault et al., 2000). Alternatively to the slow development of a leakage pathway, a leakage problem may have gone undetected if monitoring and reporting of leakage problems following initial construction is not rigorously performed (Watson and Bachu, 2009). Consequently, the time of leakage reporting may not be reflective of the time at which leakage problems are developing. Therefore, there is uncertainty as to whether leakage problems detected among deviated wellbores later over the life of the wellbore are attributed to construction challenges or other mechanisms such as operational stresses or wellbore deterioration (e.g., corrosion).

To improve our understanding of when leakage problems manifest in energy wellbores, industry and regulators might investigate the possibility of monitoring a set of wellbores for SCVF and GM continuously. Continuous monitoring of energy wellbores – as opposed to intermittent testing, as is common practice in Alberta – would provide the opportunity to more readily identify when leakage problems are developing. Having a better understanding of when leakage problems are developing may provide important clues as to the mechanisms responsible for the development of the leakage problems. Having a better understanding of the mechanisms responsible for the development of leakage problems can help focus research where it is needed.

Continuous monitoring has been discussed in other areas as having the potential to improve our understanding of wellbore leakage. Intermittent testing validity is based on the assumption that leakage from energy wellbores is continuous over time so that single samples in time reflect the actual long-term behaviour of the well. However, research suggests that leakage from energy wellbores, particularly in the form of GM from depth, is not continuous over time; rather, leakage over time is quite variable and gas is often noted to be released in pulses (Gorody, 2012; Hull, 2013). Since intermittent tests are short, they only provide a snapshot of leakage problems at the time of testing and do not necessarily provide an accurate characterization of leakage. Leakage problem data may be characterized by an inaccurate flow rate, either too low or high in various cases. Too high a leakage estimate may consequently lead to costly and unnecessary remedial work overs. Therefore, not only may continuous monitoring improve our understanding of when leakage problems are developing in energy wellbores, it may further help improve the quantification of leakage emissions from energy wellbores.

The finding that there are statistically significant differences in the average occurrence rate of leakage problems among deviated wellbores when evaluating the effect of other study factors (Sections 4.2 to 4.4) may have further implications regarding the mechanisms responsible for the development of leakage problems among deviated wellbores. If construction challenges are the only mechanism responsible for the development of leakage problems among deviated wellbores, then it might be expected that the average occurrence rate of leakage problems would be similar among all deviated wellbores, regardless of any other factor; however, the average occurrence rate of leakage problems is variable among deviated wellbores depending on the well type, drilling contractor and whether the wellbore has a reported drilling issue. This finding appears to suggest that various mechanisms other than construction challenges contribute to the development of leakage problems among deviated wellbores. Future research might investigate why some deviated wellbores are more prone to leakage problems than other deviated wellbores by considering differences in well type, drilling contractor and reported drilling issues.

The statistically insignificant difference in the average occurrence rate of leakage problems between deviated and horizontal wellbores (Section 4.1) has relevance to the development of leakage problems between different well designs. Although past research has focused on the high occurrence of leakage problems among deviated wellbores, the findings of this study indicate that deviated wellbores are not the only well design prone to leakage problems. Rather, since both deviated and horizontal wellbores have a statistically higher average occurrence rate of leakage problems than vertical wellbores, this finding suggests that non-vertical wellbores in general are more prone to leakage problems than vertical wellbores.

There is uncertainty regarding the principal mechanisms responsible for the development of leakage problems among horizontal wellbores. One possible explanation is that horizontal wellbores are difficult to construct because of similar construction challenges encountered in deviated wellbores. Horizontal wellbores have a non-vertical section near the target formation where the wellbore deviates from a vertical orientation into a horizontal orientation (i.e., from the "kick-off point" to the horizontal section - see Section 2.1 and Figures 2.2 and 5.1). Challenges centralizing the casing after the kick-off point may consequently result in poor drilling fluid displacement and cement placement issues around the casing string in this section.

There is conflicting literature as to whether construction challenges can explain the high occurrence of leakage problems among horizontal wellbores. If construction challenges are responsible for the high occurrence rate of leakage problems, then the source of the problem would consequently be arising from below the kick-off point and possibly involve the target formation itself. According to the literature, leakage problems that arise from such depths that subsequently manifest at the surface are highly unlikely because of: a) superior cement quality at the bottom of the well because of hydrostatic pressure in the cement giving a greater density; b) multiple barriers and leak-off zones in the vertical section intercepting leaks from below; and c) depletion of target formation pressures over time (see Section 2.2). Therefore, although horizontal wellbores may be more difficult to construct than vertical wellbores, the literature suggests that leakage problems from such depths would be unlikely to manifest at the surface.

To investigate whether construction challenges are attributed to the development of leakage problems among horizontal wellbores, future research should focus on the source depth of leakage problems from horizontal wellbores. Leakage problems developing as a consequence of construction problems would be expected to be originating from a depth near the kick-off point and the radius section. Leakage problems originating from some other depth, such as an intermediate depth formation, may be indicative of some other mechanism.

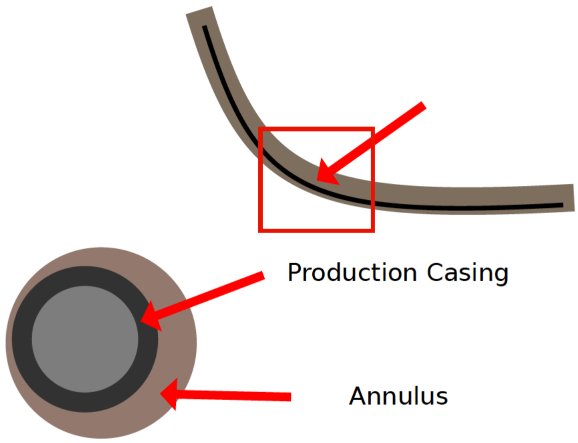

Figure 5.1. Schematic of an eccentric casing in a horizontal wellbore.

Similar to deviated wellbores, the finding that the average occurrence rate of leakage problems is statistically different among horizontal wellbores when evaluating the effect of other study factors (Sections 4.2 to 4.4) may have important implications regarding the mechanisms responsible for the development of leakage problems. Since some horizontal wellbores are more prone to leakage problems than other horizontal wellbores depending on the well type, drilling contractor, or reported drilling issues, this finding appears to suggest that there is not a single mechanism responsible for the development of leakage problems. Thus, in addition to construction challenges, future research might investigate why some horizontal wellbores are more prone to leakage problems than other horizontal wellbores by considering differences in well type, drilling contractor and reported drilling issues.

The finding that vertical wellbores had a greater total number of reported leakage problems than horizontal wellbores suggests that consideration of the total number of wellbores drilled is important when comparing the occurrences of leakage problems between groups of wellbores. (Section 4.1). Although some wellbores are more prone to leakage problems than others, wellbores that are less prone to leakage problems might be of greater concern if there is a significant difference in the total number of wellbores drilled. Essentially, it appears that a low average occurrence rate of leakage problems among a larger well population may result in a greater total number of reported leakage problems than a high average occurrence rate of leakage problems among a smaller well population. Of course, the proportion of vertical versus horizontal wells continues to change rapidly.

The finding that there has been a shift from drilling predominantly vertical wellbores to more equal proportions of each well design in recent years (Section 4.1) may have ramifications on the future proportion of leakage problems corresponding to vertical, horizontal and deviated wellbores. Vertical wellbores are of concern because of the total number of vertical wellbores drilled historically in comparison to other well designs is large. However, since the total number of vertical wellbores spud annually is decreasing in time, vertical wellbores are expected to become of less concern in the coming years. In contrast to this, there has been a growth in the total number of non-vertical wellbores spud annually. As a result, the total number of reported leakage problems corresponding to non-vertical wellbores is expected to increase in the coming years. Therefore, the proportion of non-vertical wellbores with reported leakage problems is expected to increase, whereas the proportion of vertical wellbores with reported leakage problems is expected to decrease.

5.2.2 Well Type

The finding that there were statistically significant differences in the average occurrence of leakage problems between each well type (Section 4.2) may have implications related to the influence of operational stresses on the development of leakage problems. This study investigated whether wellbores licensed to produce a particular hydrocarbon type (gas, crude bitumen or crude oil) were more prone to leakage problems than wellbores licensed to produce another hydrocarbon. Based on discussions in the literature, well type was expected to have an influence on the development of leakage problems since, depending on the target hydrocarbon, there may be particular activities required for the production of the resource that may impose occasional or cyclic pressure and/or thermal stresses on the wellbore. Intermittent pressure or temperature changes imposed on wellbores can alter the radial stress on the cement sheath, perhaps cyclically, which over time may result in the development of a microannular channel (see Section 2.6.2). The most vulnerable wellbores are expected to be those that are licensed to produce substances that require the use of enhanced recovery methods, because such operations, e.g., cyclic steam stimulation (CSS), expose wellbores to high temperatures (up to 325^{o}C) and pressures that typically exceed reservoir fracture pressure (10 to 12 MPa at depths of $\sim$400-500 m) (Lunn et al., 2009). Likewise, wellbores licensed to produce substances that require the intermittent injection of high pressure fluids are further expected to have a high occurrence rate of leakage problems as a result of the elevated and cyclic stresses imposed on the wellbores. The findings of this study supported that some well types are more prone to leakage problems than others; however, since there was insufficient information regarding which activities were performed on each wellbore, this study did not investigate the relationship between particular operational activities and the development of wellbore leakage. Future research might investigate whether the observed difference in the average occurrence rate of leakage problems between the well types is related to particular production activities that expose the wellbores to elevated operational stresses.

The finding that well design had a relationship with the total number of leakage problems among each well type (Section 4.2) may have implications regarding the occurrence of leakage problems among each well type. Depending on the target substance, a particular well design may be required to economically produce the resource. For example, horizontal wellbores are required for the production of shale gas because shale formations generally cannot be economically produced by vertical wellbores (Speight, 2013). If a particular well type requires a well design that is prone to leakage problems, i.e., a non-vertical wellbore, then the occurrence rate of leakage problems among a particular well type may be more attributed to challenges constructing the wellbore rather than operational stresses imposed on the wellbore later in time. This may require regulators to establish a different set of regulations regarding acceptable gas emissions for wells of different types.

5.2.3 Drilling Contractor

The finding that there were statistically significant differences in the average occurrence rate of leakage problems among wellbores drilled by the Major Drilling Contractors (Section 4.3) may be indicative of differences in construction practices. Each company has its own internal standards and best practices for constructing wellbores. Some best practices are more effective at obtaining an adequate initial cement seal than others, and therefore the occurrence of leakage problems can be reasonably expected to be variable among different companies. Furthermore, other factors such as equipment availability and time constraints may consequently generate the "...pressure to do more with less" (Watson and Bachu, 2009), so that best practices may not always be used. For example, Watson and Bachu found a strong relationship between oil prices and the occurrence of leakage problems. The authors attributed this finding to the larger financial incentive to drill wellbores more rapidly and to move on to the next well in times of high prices, and also to more rapidly develop heavy-oil areas of Alberta. But, in times of low prices, there may be other incentives to perform cementing operations quickly and less carefully. Therefore, the observed differences in the average occurrence rate of leakage problems between the Major Drilling Contractors may be attributed to varying best practices, or deficiencies in quality assurance when constructing the wellbores because of equipment or time constraints.

Alternatively to poor construction practices, the difference in the average occurrence rate of leakage problems between wellbores drilled by a particular drilling contractor could be an artifact of varying monitoring and reporting of leakage problems. In Alberta, the AER regulates when wellbores must be tested for leakage problems; however, the method by which wellbores are tested for leakage problems is unregulated (see Section 2.4.2). More stringent internal standards within a particular company for testing wellbore leakage may possibly result in a difference in the detection and subsequent reporting of leakage problems. Furthermore, the average occurrence rate of leakage problems may be apparently higher among a particular company if the wellbores were primarily drilled within the Test Area of Alberta. The additional testing and reporting requirements for GM within this region may consequently result in a higher average occurrence rate of leakage relative to contractors that mainly drilled wellbores outside of the Test Area.

5.2.4 Reported Drilling Issues

Wellbores without reported drilling issues were found to have a higher occurrence rate of leakage problems than wellbores with reported drilling issues (Section 4.4). Wellbores with reported drilling issues, particularly those issues that may impair the circulation of drilling fluid to the surface such as lost circulation or a stuck casing string, were expected to have a higher occurrence rate of leakage problems than wellbores without reported drilling issues, possibly because of poor well cleaning. If drill cuttings and other contaminants are not adequately displaced out of the wellbore annulus prior to the placement of the cement slurry, then an adequate cement-to-casing and cement-to-rock wall bond may not form at these interfaces, which may consequently result in the formation of a microannulus. Furthermore, if contaminants become embedded within the cement slurry, it may inhibit cement gelation, reduce the compressive strength of the set cement, or generate a void space that may provide a conduit for formation fluids (see Section 2.6.1). Drill cuttings and other contaminants are generally carried out of the wellbore by circulating a drilling fluid (generally a clay-water mixture and other additives) down the drill string and up through the annulus around the pipe (see Section 2.1). However, this process may be vitiated as a result of lost circulation, because the drilling fluid is not flowing to the surface. The circulation of drill cuttings to the surface may further be impeded if a drill string becomes stuck in the formation (Aldred et al., 1999). Therefore, some drilling issues may result in poor well cleaning which consequently may lead to the development of leakage problems.

Drilling issues may further be associated with the development of leakage problems if high pressure formations, kicks or blowouts are encountered. Invasion of formation fluids was identified as a common mechanism associated with the development of leakage problems (see Section 2.6.1). Formation fluids flowing into the wellbore may generate channels in the cement sheath, which later may serve as a conduit for fluids to the surface. Formation fluids may flow into the wellbore if the hydrostatic pressure of the drilling fluid drops below the hydrostatic pressure of the surrounding formation. These conditions are most likely to be met when high pressure formations are encountered during the drilling of the wellbore. Therefore, wellbores drilled through high pressure formations and particularly wellbores with reports of kicks or blowouts may be more likely to develop leakage problems.

One can only speculate as to why wellbores with reported drilling issues have a lower average occurrence rate of leakage problems than wellbores without reported drilling issues. Perhaps industry is managing the risks presented by drilling issues appropriately as to prevent larger problems arising in the future. As discussed by Aldred et al. (1999), drilling issues are costly for the industry; approximately 15% of money spent by industry on drilling is attributed to loss of drilling equipment, fluids and time (i.e., non-productive time, NPT) for planning remedies. In more complicated cases, drilling issues can threaten subsequent completion and production activities possibly resulting in a total loss of the well. Therefore, it is in industry's best interest to manage drilling risks appropriately. Consequently, any potential problems arising from drilling issues may have been addressed accordingly as to prevent further issues from arising.

6 CONCLUSIONS

The purpose of this study has been to investigate factors influencing the occurrence of energy wellbore leakage. Overall, this study indicated that there are occurrences of leakage problems that prove to be statistically significant in relation to well design, well type, drilling contractor and reported drilling issues. The major conclusions from this study are as follows:

- *Well Design*

  - **Deviated wellbores are prone to leakage problems, but there is uncertainty regarding the mechanisms responsible** – Consistent with the literature, deviated wellbores overall are statistically more prone to leakage problems than vertical wellbores. However, the results of this study did not support that leakage problems are developing mainly as a consequence of construction challenges. First, most leakage problems are reported during the operational life of the wellbore. This raises uncertainty as to whether construction challenges are responsible for the development of leakage problems or other mechanisms such as operational stresses or wellbore deterioration. Second, statistically significant differences in the average occurrence rate of leakage problems exist between deviated wellbores depending on well type, drilling contractor and whether the wellbore had a reported drilling issue. If construction challenges are solely responsible for the development of leakage problems, then it would be expected that average occurrence rate of leakage problems would be similar among all deviated wellbores, regardless of any other factor.

    Continuous monitoring of a subset of deviated wellbores – as opposed to intermittent testing – may provide important clues regarding the mechanisms responsible for the development of leakage problems. This may help industry and regulators make more informed decisions for mitigating leakage problems. Furthermore, future research might focus on the why there are statistically significant differences in the average occurrence rate of leakage problems among deviated wellbores depending on well type, drilling contractor and reported drilling issues so that the mechanisms responsible for the development of leakage problems are better quantified and understood.

- **Horizontal wellbores have a statistically higher average occurrence rate of leakage problems than vertical wellbores, suggesting that non-vertical wellbores in general are prone to leakage problems** – Previous research has found that wellbore deviation is a major factor associated with the development of leakage problems. Although deviated wellbores were found to be more prone to leakage problems than vertical wellbores, there was no evidence to support that deviated wellbores were more prone to leakage problems than horizontal wellbores. Rather, the data suggested that non-vertical wellbores in general are more prone to leakage problems than vertical wellbores.
- **There is uncertainty regarding the principal mechanisms responsible for the high average occurrence rate of leakage among horizontal wellbores** – The high average occurrence rate of leakage problems among horizontal wellbores is possibly attributed to similar construction challenges at the kick-off point and deviated section as to those encountered among deviated wellbores; however, there is conflicting literature regarding whether this is possible, because some research suggests that leakage problems manifesting at the surface from such depths is unlikely. Furthermore, the average occurrence rate of leakage problems among horizontal wellbores is variable depending on the well type, drilling contractor and whether the wellbore has reported drilling issues. This finding suggests that construction challenges alone cannot be responsible for the development of leakage problems among horizontal wellbores.

  Future research might investigate if there is a relationship between the source depth of leakage problems from horizontal wellbores and the depth of the kick-off point to determine if construction challenges can explain the development of leakage problems among horizontal wellbores. In addition, future research might focus on why there are statistically significant differences in the average occurrence rate of leakage problems among horizontal wellbores of particular well types, drilling contractor and reported drilling issues so that the mechanisms responsible for the develop of leakage problems are better quantified and understood.
- **Consideration of the total number of wellbores drilled is important when com-**

paring the occurrences of leakage problems between groups of wellbores – Identification of groups of wellbores with a high average occurrence rate of leakage problems helps establish which wellbores are prone to leakage problems. However, identification of groups of wellbores with a low average occurrence rate of leakage problems does not necessarily indicate that the wellbores are not of concern. Depending on the total number of wellbores drilled, wellbores with a low average occurrence rate of leakage problems may have a high total number of reported leakage problems. As an example, horizontal wellbores have a statistically higher average occurrence rate of leakage problems than vertical wellbores, but vertical wellbores have a greater total number of reported leakage problems, possibly attributed to the fact that four-times more vertical wellbores were spud during the study period.

- **The proportion of vertical, horizontal and deviated wellbores with reported leakage problems is expected to change in the coming years as a consequence of changing drilling activity** – At the beginning of the study period, most wellbores spud across Alberta were vertical. However, by the end of the study period, there was near equal proportions of vertical, horizontal and deviated wellbores spud. Since non-vertical wellbores have a higher average occurrence rate of leakage problems than vertical wellbores, the proportion of non-vertical wellbores with reported leakage problems is expected to increase whereas the proportion of vertical wellbores with leakage problems is expected to decrease.

• *Well Type*

- **Differences in the average occurrence rate of leakage problems between wellbores producing different hydrocarbons may be related to different operational stresses imposed on the wellbores** – Watson and Bachu (2009) previously discussed that well-operational mode may have an influence on the development of leakage problems, because depending on production activities, there may be varying levels of operational stresses imposed on the wellbores. Wellbores used for enhanced oil recovery operations, for example, are exposed to cyclic physical and thermal stresses that may increase the likelihood for the development of a microannulus. Although Watson and Bachu found no evidence to support this, the result of this study indicate that the occurrence of leakage problems is statistically different depending on what the wellbore is licensed to produce. We believe that Watson and Bachu's expectations are correct, but could not support that the observed differences between well types is attributed to production activities. Further research might investigate the observed difference in the occurrence of leakage problems between well types in greater detail by considering production activities.

  - **The difference in the average occurrence rate of leakage problems between different well types might be related to well design** – Depending on the resource, a particular well orientation may be required so that the resource can be economically produced (e.g., horizontal wellbores for shale formations). Since some well designs are more prone to leakage problems than others, then differences in the development of leakage problems between well types may be related to differences in the occurrence of leakage problems between well orientations.

- *Drilling Contractor*

  - **Differences in the average occurrence rate of leakage problems between the Major Drilling Contractors may be reflective of varying construction practices or an artifact of different internal standards for monitoring and reporting leakage problems** – A statistically significant difference was found in the average occurrence rate of leakage problems among wellbores drilled by the Major Drilling Contractors. This difference is possibly attributed to varying construction practices among the Contractors. Each company has its own internal standards and best practices for constructing wellbores, some of which are better than others. Furthermore, some companies may also experience or impose equipment or time constraints, therefore limiting the use of best practices for constructing wellbores. Consequently, wellbores drilled by a particular contractor may be more prone to leakage problems than another. Alternatively, the differences in the average occurrence rate of leakage problems among the Contractors may be an artifact of different internal standards for monitoring and reporting leakage problems. The AER does not regulate what methods are used for testing for wellbore leakage and therefore some company's methods may be more effective than others. Furthermore, if wellbores drilled by a particular company are primarily drilled within the Test Area of the Province, then the extra testing requirements in this region may result in an apparently high average occurrence rate of leakage problems for a Contractor that had experience drilling wellbores elsewhere across the Province but not in the Test Area.

- *Reported Drilling Issues*
  - **The low average occurrence rate of leakage problems among wellbores with reported drilling issues may be related to effective risk management** – Wellbores with reported drilling issues were expected to have a higher average occurrence rate of leakage problems than wellbores without reported drilling issues since drilling issues may negatively impact primary completions; however, wellbores without reported drilling issues were found to be statistically more prone to leakage problems than wellbores with reported drilling issues. We speculate that this finding is related to successful risk management of drilling issues by industry as to prevent further issues from being encountered. For instance, problems encountered during the construction of the wellbore might trigger more attention, leading to earlier corrective measures and better care before drilling and completion is complete, and consequently better outcomes.

A GLOSSARY OF TERMS

Drilling Activity General term used throughout this study to describe the total number wellbores drilled during the study period. Drilling activity was used broadly to describe the total number of wellbores drilled overall, and also used more specifically to describe the total number of wellbores drilled among a particular group of wellbores, e.g., vertical wellbores.

Drilling Contractor The company hired by the wellbore licensee to drill the bore hole. Between 2004 and 2013, 530 contractors drilled at least one wellbore across Alberta. The Major Drilling Contractors refers to the five most active contractors during the study period.

Drilling Issues Unforeseeable challenges encountered during the drilling of energy wellbores that may jeopardize the integrity of a wellbore if not carefully managed. The most common drilling issue reported to the AER is lost circulation, a problem where drilling fluid flows uncontrollably into an adjacent formation such as a fault, fracture, or cavernous carbonate zone. Other issues reported include kicks – forced fluid flow from the formation rock into the wellbore – and in more serious cases when the kick cannot be controlled, blowouts.

Drill Rig Release The date when the equipment used for drilling and completing a wellbore is removed from site. At this time, the wellbore is ready for production, but production has not yet begun. The Alberta Energy Regulator requires wellbores be tested for leakage problems within 90 days of this date.

Gas Migration Leakage of subsurface fluids (e.g., gas, brine, hydraulic fracturing fluids) outside of the outermost casing string, i.e., the surface casing, of an energy wellbore. Possible leakage pathways include: i) a microannular channel located either between the cement sheath and the borehole wall or between the cement sheath and the surface casing string; and ii) drilling damage to the borehole wall, such as washed-out areas and drilling induced micro fissures, into which the cement was not adequately placed.

Leakage Report Date The date a leakage problem was reported to the Alberta Energy Regulator. By regulation, leakage problems must be tested and reported within 90 days of drill rig release and at the time of final abandonment.

Spud Date The date the drilling commences of an energy wellbore.

Statistical Significance The observed significance level, i.e., *p-value*, "reports the extent to which the test statistic (i.e., z) disagrees with the null hypothesis" (McClave and Sincich, 2009). For a mean comparison test, the null hypothesis would be that there is not a statistically significant difference between the groups of wellbores. If the *p-value* is less than or equal to 0.05, then the test is said to be statistically significant and the null hypothesis would be rejected.

Surface Casing Vent Flow Leakage of subsurface fluids (e.g., gas, brine, hydraulic fracturing fluids) between the surface casing and the next innermost casing string. Possible leakage pathways include: i) a microannular channel located between the cement sheath and a casing string; and ii) discontinuities in the cement sheath, such as channels or fractures.

Township The term township refers to a 36 square mile (or approximately 93 km^2) quadrilateral. The location of the township is described by a pair of numbers – township and range – following the Alberta's Township Survey System.

Well Design Refers to the orientation (vertical, horizontal, or deviated) of an energy wellbore. In vertical wellbores, the total depth (TD) is equal to the true vertical depth (TVD). Deviated wellbores have a TD that is greater than the TVD. Horizontal wellbores are initially drilled vertically or at an inclination, but deviate to become horizontal within the last few hundred meters for the target formation is reached and then drilled horizontally along the target formation.

Well Type Refers to the hydrocarbon (natural gas, crude bitumen, or crude oil) that the wellbore is licensed to produced. Wellbores licensed to produce other substances are less abundant and therefore were not the focus of this study. Coalbed methane was not included in the natural gas analysis.

B SAMPLE CHARACTERISTICS

As summarized in Table B.1, the mean proportion of wellbores with reported leakage problems and per township was larger than the median value for each factor, suggesting that the data was non-normally distributed. This observation was confirmed by the skewness statistic where: a) the absolute value of the skewness statistic exceeded 1, and b) the skewness statistic was greater than two-times the standard error.

Table B.1. Distribution of the proportion of wellbores with reported leakage problems per township with respect to each factor (Mean = mean proportion of wellbores with reported leakage problems per township, Median = median proportion of wellbores with reported leakage problems per township, Skewness (statistics and standard error) = test of normality)

Factor	Drilling Contractor					Well Type			Well Design			Drilling Issues	
	A	**B**	**C**	**D**	**E**	**Gas**	**Bitumen**	**Oil**	**Vertical**	**Horizontal**	**Deviated**	**Yes**	**No**
Overall													
Mean	5.22	3.72	4.05	5.50	4.51	3.68	3.28	6.08	3.24	7.05	6.37	5.56	8.88
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Skewness Stat.	4.32	4.96	4.70	4.00	4.56	5.50	5.36	3.85	5.47	3.57	3.69	4.00	3.03
Std.Error	0.044	0.072	0.065	0.067	0.064	0.040	0.092	0.056	0.038	0.060	0.045	0.051	0.057
Yes													
Mean	5.71	2.13	7.86	7.52	4.46	4.99	6.48	4.42	3.83	6.99	8.06		
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Skewness Stat.	3.89	6.81	3.15	3.22	4.48	4.30	3.62	4.45	4.92	3.43	3.12		
Std.Error	0.075	0.146	0.162	0.138	0.137	0.064	0.097	0.137	0.058	0.112	0.075		
No													
Mean	9.01	6.49	13.18	9.52	8.24	8.90	8.72	7.67	8.31	7.10	11.51		

Continued on next page

Table B.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Skewness Stat.	2.95	3.57	2.19	2.84	3.11	2.96	3.04	3.19	3.08	3.51	2.48		
Std.Error	0.086	0.187	0.162	0.139	0.147	0.084	0.084	0.165	0.074	0.082	0.083		
Vertical													
Mean	3.72	3.35	2.92	4.48	4.29	3.05	5.56	6.85					
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00					
Skewness Stat.	5.03	5.32	5.69	4.39	4.61	5.90	4.05	6.85					
Std.Error	0.048	0.074	0.070	0.084	0.076	0.041	0.064	0.094					
Horizontal													
Mean	7.18	1.85	12.57	6.10	5.80	5.73	6.32	9.35					
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00					
Skewness Stat.	3.40	5.20	2.30	3.74	3.91	3.97	3.81	2.85					
Std.Error	0.085	0.448	0.198	0.119	0.130	0.107	0.081	0.203					
Deviated													
Mean	6.93	5.82	7.02	6.25	4.36	5.82	7.69	9.75					
Median	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00					

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Table B.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Skewness Stat.	3.52	3.83	3.42	3.60	4.58	3.90	3.21	2.59					
Std.Error	0.058	0.142	0.106	0.099	0.097	0.053	0.073	0.170					
Gas													
Mean	4.08	2.05	2.98	4.25	4.51								
Median	0.00	0.00	0.00	0.00	0.00								
Skewness Stat.	4.96	7.01	5.63	4.64	4.52								
Std.Error	0.051	0.081	0.077	0.092	0.083								
Bitumen													
Mean	6.26	9.70	2.41	7.54	2.20								
Median	0.00	0.00	0.00	0.00	0.00								
Skewness Stat.	3.16	2.74	6.45	2.96	7.16								
Std.Error	0.140	0.267	0.205	0.180	0.178								
Oil													
Mean	7.39	12.53	9.13	5.84	5.19								
Median	0.00	0.00	0.00	0.00	0.00								
Skewness Stat.	3.38	2.31	2.81	3.95	4.12								

Continued on next page

Table B.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Std.Error	0.076	0.210	0.120	0.111	0.122								

C DESCRIPTION OF DRILLING ACTIVITY

Table C.1. Descriptive statistics of wellbores spud across Alberta during the study period (Sum=total number of wellbores spud, N=number of townships)

Factor	Drilling Contractor					Well Type			Well Design			Drilling Issues	
	A	**B**	**C**	**D**	**E**	**Gas**	**Bitumen**	**Oil**	**Vertical**	**Horizontal**	**Deviated**	**Yes**	**No**
Overall													
Sum	33,874	17,866	9,505	7,881	7,773	58,595	31,333	20,051	85,416	20,529	31,969	8,873	14,413
N	3,079	1,147	1,422	1,329	1,477	3,786	702	1,930	4,220	1,687	2,944	2,267	1,836
Yes													
Sum	2,566	787	372	553	498	4,433	1,100	1,466	4,903	1,230	2,740		
N	1,058	287	227	311	319	1,452	316	635	1,770	476	1,066		
No													
Sum	4,708	542	522	1,508	815	2,492	4,306	4,377	3,249	6,197	4,967		
N	806	168	225	307	275	854	217	852	1,086	883	872		
Vertical													
Sum	15,752	15,314	6,509	2,686	4,846	42,184	20,736	6,812					
N	2,551	1,083	1,222	840	1,046	3,541	673	1,462					
Horizontal													
Sum	5,843	39	409	2,367	1,539	2,444	3,971	7,568					

Table C.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Bitumen													
Sum	6,166	624	714	3,128	2,586								
N	303	81	140	183	187								
Oil													
Sum	5,380	374	1,587	1,351	1,581								
N	1,024	133	416	480	400								

D DESCRIPTION OF LEAKAGE REPORTS

Table D.1. Descriptive statistics of the occurrence of leakage problems across Alberta during the study period (Sum=total number of wellbores spud, N=number of townships)

Factor	Drilling Contractor					Well Type			Well Design			Drilling Issues	
	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Overall													
Sum	1,884	164	311	517	220	1,410	1,471	1,447	1,590	1,178	2,452	371	1,007
N	3,079	1,147	1,422	1,329	1,477	3,786	702	1,930	4,220	1,687	2,944	2,267	1,836
Yes													
Sum	121	9	23	45	21	169	52	84	131	59	181		
N	1,058	287	227	311	319	1,452	316	635	1,770	476	1,066		
No													
Sum	395	14	81	130	46	126	395	330	203	267	537		
N	806	168	225	307	275	854	217	852	1,086	883	872		
Vertical													

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Table D.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Sum	353	123	111	71	102	798	226	410					
N	2,551	1,083	1,222	840	1,046	3,541	673	1,462					
Horizontal													
Sum	349	1	48	89	60	119	186	436					
N	825	27	150	424	350	517	142	902					
Deviated													
Sum	1,181	40	152	357	58	493	1,059	601					
N	1,784	296	536	605	629	2,122	205	1,124					
Gas													
Sum	367	68	86	73	84								
N	2,313	920	1,019	710	878								
Bitumen													
Sum	754	32	5	294	23								
N	303	81	140	183	187								
Oil													

Continued on next page

Table D.1 – continued from previous page

Factor	A	B	C	D	E	Gas	Bitumen	Oil	Vertical	Horizontal	Deviated	Yes	No
Sum	481	47	185	73	75								
N	1,024	133	416	480	400								

E MEAN COMPARISON TEST RESULTS

E.1 Overall

Table E.1a. Kruskal-Wallis nonparametric test summaries comparing well design, well type and drilling contractor against overall leak occurrence across Alberta (*n* = number of townships, *MR* = mean rank, χ^2 = test statistic, *df* = degrees of freedom, *p* = significance level).

Factor	N	Leak Occurrence			
		MR	χ^2	*df*	*p*
Well Design					
Vertical	4,220	4,318.80	29.27	2	0.00
Horizontal	1,687	4,470.32			
Deviated	2,944	4,554.27			
Total	8,851				
Well Type					
Gas	3,786	3,178.59	34.82	2	0.00
Crude Oil	1,930	3,340.45			
Crude Bitumen	702	3,016.17			
Total	6,418				
Drilling Contractor					
A	3,079	4,421.31	91.49	4	0.00
B	1,147	4,044.71			
C	1,422	4,109.59			
D	1,329	4,204.80			
E	1,477	4,099.36			
Total	8,454				

Table E.1b. Mann-Whitney nonparametric test summaries of overall leak occurrence across Alberta (n = number of townships, MR = mean rank, U = Mann-Whitney U test statistic, z = z-score, df = degrees of freedom, p = significance level).

Factor	N	Leak Occurrence			
		MR	*U*	*z*	*p*
Well Design					
Vertical	4,220	2,925.90	3,440,998.50	-2.82	0.01
Horizontal	1,687	3,024.29			
Vertical	4,220	3,503.40	5,878,017.00	-5.36	0.00
Deviated	2,944	3,695.89			
Horizontal	1,687	2,290.03	2,439,460.00	-1.35	0.18
Deviated	2,944	2,330.88			
Well Type					
Gas	3,786	2,809.31	3,467,264.00	-4.30	0.00
Crude Oil	1,930	2,954.99			
Gas	3,786	2,262.78	1,259,688.50	-3.10	0.00
Crude Bitumen	702	2,145.93			
Crude Oil	1,930	1,350.96	610,913.00	-5.24	0.00
Crude Bitumen	702	1,221.75			
Drilling Contractor					
A	3,079	2,165.36	1,606,124.00	-7.02	0.00
B	1,147	1,974.28			
A	3,079	2,303.47	2,027,628.50	-6.17	0.00
C	1,422	2,137.40			
A	3,079	2,237.82	1,943,396.00	-4.03	0.00
D	1,329	2,127.30			
A	3,079	2,334.66	2,100,921.50	-6.47	0.00
E	1,477	2,161.42			

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Table E.1b – continued from previous page

Factor	**N**	*MR*	*U*	*z*	*p*
B	1,147	1,274.52	803,496.50	-1.21	0.23
C	1,422	1,293.45			
B	1,147	1,214.28	734,400.00	-2.82	0.01
D	1,329	1,259.40			
B	1,147	1,303.63	836,883.50	-1.00	0.32
E	1,477	1,319.39			
C	1,422	1,361.37	924,115.50	-1.76	0.08
D	1,329	1,391.65			
C	1,422	1,451.87	1,047,485.00	-0.22	0.83
E	1,477	1,448.20			
D	1,329	1,421.45	957,617.00	-1.98	0.05
E	1,477	1,387.35			
Drilling Issues					
Yes	2,267	1,970.37	1,896,042.00	-7.53	0.00
No	1,836	2,152.80			

E.2 Controlled Well Type

Table E.2a. Kruskal-Wallis nonparametric test summaries comparing well type and drilling contractor against leak occurrence controlling well type (*n* = number of townships, *MR* = mean rank, χ^2 = test statistic, *df* = degrees of freedom, *p* = significance level).

Gas					
Factor	*N*	*MR*	χ^2	*df*	*p*
Well Design					
Vertical	3,541	3,073.02	3.49	2	0.18
Horizontal	517	3,058.58			
Deviated	2,122	3,127.45			
Total	6,180				
Drilling Contractor					
A	2,313	2,994.67	34.14	4	0.00
B	920	2,835.94			
C	1,019	2,850.67			
D	710	2,900.85			
E	878	2,910.65			
Total	5,840				
Crude Bitumen					
Well Design					
Vertical	673	470.31	101.11	2	0.00
Horizontal	142	540.42			
Deviated	205	621.72			
Total	1,020				
Drilling Contractor					
A	303	478.25	46.47	4	0.00
B	81	454.65			
C	140	389.25			
Continued on next page					

Table E.2a – continued from previous page

Factor	N	MR	χ^2	df	p
D	183	481.62			
E	187	404.80			
Total	894				
Crude Oil					
Well Design					
Vertical	1,462	1,690.49	18.30	2	0.00
Horizontal	902	1,754.37			
Deviated	1,124	1,806.83			
Total	3,488				
Drilling Contractor					
A	1,024	1,254.24	22.58	4	0.00
B	133	1,294.17			
C	416	1,260.48			
D	480	1,168.65			
E	400	1,170.13			
Total	2,453				

Table E.2b. Mann-Whitney nonparametric test summaries for the occurrence of leakage problems across Alberta controlling well type (n = number of townships, MR = mean rank, U = Mann-Whitney U test statistic, z = z-score, df = degrees of freedom, p = significance level).

Gas					
Factor	*N*	*MR*	*U*	*z*	*p*
Drilling Contractor					
A	2,313	1,642.38	1,005,268.50	-4.63	0.00
B	920	1,553.18			
A	2,313	1,691.72	1,120,150.00	-4.31	0.00
C	1,019	1,609.26			
A	2,313	1,523.22	795,171.00	-2.34	0.02
D	710	1,475.46			
A	2,313	1,608.35	986,837.50	-2.26	0.02
E	878	1,563.46			
B	920	967.72	466,641.50	-0.39	0.69
C	1,019	972.06			
B	920	807.89	319,602.00	-1.64	0.10
D	710	825.36			
B	920	888.64	393,892.50	-1.97	0.05
E	878	910.88			
C	1,019	859.09	355,721.50	-1.29	0.20
D	710	873.48			
C	1,019	940.26	438,432.50	-1.62	0.11
E	878	959.15			
D	710	793.06	310,664.50	-0.23	0.82
E	878	795.67			
Drilling Issue					
Yes	1,452	1,137.17	596,289.50	-2.76	0.01

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Table E.2b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
No	854	1,181.27			
Crude Bitumen					
Well Design					
Vertical	673	398.36	41,297.50	-4.59	0.00
Horizontal	142	453.67			
Vertical	673	408.95	48,419.00	-10.12	0.00
Deviated	205	539.81			
Horizontal	142	158.25	12,318.00	-2.94	0.00
Deviated	205	184.91			
Drilling Contractor					
A	303	194.40	11,697.00	-0.88	0.38
B	81	185.41			
A	303	236.03	16,957.50	-5.11	0.00
C	140	191.63			
A	303	242.68	27,476.00	-0.22	0.83
D	183	244.86			
A	303	261.14	23,591.50	-4.67	0.00
E	187	220.16			
B	81	120.53	4,898.00	-3.47	0.00
C	140	105.49			
B	81	127.50	7,006.50	-0.97	0.33
D	183	134.71			
B	81	144.21	6,787.00	-2.54	0.01
E	187	130.29			
C	140	143.18	10,175.50	-5.03	0.00
D	183	176.40			
C	140	160.46	12,594.50	-1.45	0.15

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Table E.2b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
E	187	166.65			
D	183	201.65	14,155.00	-4.51	0.00
E	187	169.70			
Drilling Issue					
Yes	316	247.74	28,200.00	-5.34	0.00
No	217	295.05			
Crude Oil					
Well Design					
Vertical	1,462	1,165.74	634,858.50	-2.30	0.02
Horizontal	902	1,209.67			
Vertical	1,462	1,256.25	767,188.00	-4.25	0.00
Deviated	1,124	1,341.95			
Horizontal	902	996.20	491,319.50	-1.67	0.10
Deviated	1,124	1,027.38			
Drilling Contractor					
A	1,024	576.68	65,718.00	-0.95	0.34
B	133	596.88			
A	1,024	719.20	211,657.00	-0.27	0.79
C	416	723.71			
A	1,024	769.45	228,407.00	-3.40	0.00
D	480	716.35			
A	1,024	726.42	190,547.00	-3.11	0.00
E	400	676.87			
B	133	281.02	26,863.50	-0.73	0.47
C	416	273.08			
B	133	330.65	28,775.00	-2.91	0.00

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Table E.2b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
D	480	300.45			
B	133	286.63	23,989.50	-2.79	0.01
E	400	260.47			
C	416	466.16	92,494.50	-3.06	0.00
D	480	433.20			
C	416	423.04	77,152.50	-2.85	0.00
E	400	393.38			
D	480	440.16	95,836.50	-0.08	0.94
E	400	440.91			
Drilling Issue					
Yes	635	704.77	245,601.50	-4.65	0.00
No	852	773.24			

E.3 Controlled Drilling Contractor

Table E.3a. Kruskal-Wallis nonparametric test summaries comparing well type and drilling contractor against leak occurrence controlling drilling contractor (*n* = number of townships, *MR* = mean rank, χ^2 = test statistic, *df* = degrees of freedom, *p* = significance level).

Contractor A					
Factor	*N*	*MR*	χ^2	*df*	*p*
Well Design					
Vertical	2,551	2,487.33	56.91	2	0.00
Horizontal	825	2,626.86			
Deviated	1,784	2,692.28			
Total	5,160				
Well Type					
Gas	2,313	1,764.23	50.66	2	0.00
Crude Bitumen	303	1,979.67			
Crude Oil	1,024	1,900.51			
Total	3,640				
Contractor B					
Well Design					
Vertical	1,083	701.61	1.64	2	0.44
Horizontal	27	669.98			
Deviated	296	713.45			
Total	1,406				
Well Type					
Gas	920	552.81	40.80	2	0.00
Crude Bitumen	81	616.56			
Crude Oil	133	639.23			
Total	1,134				
Contractor C					

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Table E.3a – continued from previous page

Factor	*N*	*MR*	χ^2	*df*	*p*
Well Design					
Vertical	1,222	923.31	43.37	2	0.00
Horizontal	150	1,043.35			
Deviated	536	1,000.75			
Total	1,908				
Well Type					
Gas	1,019	764.71	56.58	2	0.00
Crude Bitumen	140	739.88			
Crude Oil	416	861.24			
Total	1,575				
Contractor D					
Well Design					
Vertical	840	907.84	14.27	2	0.00
Horizontal	424	947.63			
Deviated	605	963.86			
Total	1,869				
Well Type					
Gas	710	665.23	32.92	2	0.00
Crude Bitumen	183	770.60			
Crude Oil	480	687.32			
Total	1,373				
Contractor E					
Well Design					
Vertical	1,046	1,006.96	4.33	2	0.12
Horizontal	350	1,041.67			
Deviated	629	1,007.09			
Continued on next page					

Table E.3a – continued from previous page

Factor	*N*	*MR*	χ^2	*df*	*p*
Total	2,025				
Well Type					
Gas	878	728.31	4.29	2	0.12
Crude Bitumen	187	716.60			
Crude Oil	400	750.96			
Total	1,465				

Table E.3b. Mann-Whitney nonparametric test summaries for the occurrence of leakage problems across Alberta controlling drilling contractor (*n* = number of townships, *MR* = mean rank, *U* = Mann-Whitney U test statistic, *z* = *z*-score, *df* = degrees of freedom, *p* = significance level).

Contractor A					
Factor	*N*	*MR*	*U*	*z*	*p*
Well Design					
Vertical	2,551	1,666.43	995,975.50	-4.13	0.00
Horizontal	825	1,756.76			
Vertical	2,551	2,096.91	2,094,132.00	-7.46	0.00
Deviated	1,784	2,269.66			
Horizontal	825	1,283.10	717,836.50	-1.52	0.13
Deviated	1,784	1,315.13			
Well Type					
Gas	2,313	1,290.37	308,493.50	-5.74	0.00
Crude Bitumen	303	1,446.87			
Gas	2,313	1,630.85	1,096,023.00	-5.67	0.00
Crude Oil	1,024	1,755.17			
Crude Bitumen	303	684.80	148,833.00	-1.53	0.13
Crude Oil	1,024	657.84			
Drilling Issue					
Yes	1,058	899.18	391,116.50	-5.18	0.00
No	806	976.24			
Contractor B					
Well Type					
Gas	920	496.45	33,072.50	-3.70	0.00
Crude Bitumen	81	522.70			
Gas	920	516.86	51,854.50	-5.93	0.00
Crude Oil	133	597.12			

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Table E.3b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
Crude Bitumen	81	104.86	5,172.50	-0.70	0.48
Crude Oil	133	109.11			
Drilling Issue					
Yes	278	219.87	22,343.00	-2.13	0.03
No	168	229.51			
Contractor C					
Well Design					
Vertical	1,222	677.15	80,230.00	-5.32	0.00
Horizontal	150	762.63			
Vertical	1,222	857.65	300,797.50	-5.46	0.00
Deviated	536	929.31			
Horizontal	150	356.22	38,292.00	-1.41	0.16
Deviated	536	339.94			
Well Type					
Gas	1,019	582.25	69,035.00	-1.45	0.15
Crude Bitumen	140	563.61			
Gas	1,019	692.46	185,925.50	-6.90	0.00
Crude Oil	416	780.56			
Crude Bitumen	140	246.78	24,678.50	-4.34	0.00
Crude Oil	416	289.18			
Drilling Issue					
Yes	227	215.99	23,151.00	-2.84	0.01
No	225	237.11			
Contractor D					
Well Design					
Vertical	840	623.48	170,506.50	-2.48	0.01

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Table E.3b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
Horizontal	424	650.36			
Vertical	840	704.86	238,859.50	-3.70	0.00
Deviated	605	748.19			
Horizontal	424	509.77	126,041.50	-0.81	0.42
Deviated	605	518.67			
Well Type					
Gas	710	432.88	54,942.50	-5.76	0.00
Crude Bitumen	183	501.77			
Gas	710	587.85	164,969.00	-1.82	0.07
Crude Oil	480	606.81			
Crude Bitumen	183	360.83	38,644.00	-3.83	0.00
Crude Oil	480	321.01			
Drilling Issue					
Yes	311	299.12	44,509.00	-2.37	0.02
No	307	320.02			
Contractor E					
Drilling Issue					
Yes	319	288.26	40,914.00	-2.79	0.01
No	275	308.22			

E.4 Controlled Drilling Issues

Table E.4a. Kruskal-Wallis nonparametric test summaries comparing well design, well type and drilling contractor against leak occurrence controlling drilling issues (n = number of townships, MR = mean rank, χ^2 = test statistic, df = degrees of freedom, p = significance level).

Yes					
Factor	*N*	*MR*	χ^2	*df*	*p*
Well Design					
Vertical	1,770	1,612.41	34.88	2	0.00
Horizontal	476	1,670.62			
Deviated	1,066	1,723.41			
Total	3,312				
Well Type					
Gas	1,452	1,199.89	1.32	2	0.52
Crude Oil	635	1,214.46			
Crude Bitumen	316	1,186.64			
Total	2,403				
Drilling Contractor					
A	1,058	1,109.24	17.44	4	0.00
B	278	1,036.39			
C	227	1,108.59			
D	311	1,124.88			
E	319	1,073.79			
Total	2,193				
No					
Well Design					
Vertical	1,086	1,377.29	14.92	2	0.00
Horizontal	833	1,423.61			
Deviated	872	1,472.80			

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Table E.4a – continued from previous page

Factor	*N*	*MR*	χ^2	*df*	*p*
Total	2,841				
Well Type					
Gas	854	921.64	20.77	2	0.00
Crude Oil	852	983.74			
Crude Bitumen	217	1,035.47			
Total	1,923				
Drilling Contractor					
A	806	903.59	14.59	4	0.01
B	168	813.14			
C	225	920.18			
D	307	904.46			
E	275	862.77			
Total	1,781				

Table E.4b. Mann-Whitney nonparametric test summaries for the occurrence of leakage problems across Alberta controlling drilling issues (n = number of townships, MR = mean rank, U = Mann-Whitney U test statistic, z = z-score, df = degrees of freedom, p = significance level).

Yes					
Factor	*N*	*MR*	*U*	*z*	*p*
Well Design					
Vertical	1,770	1,115.22	406,609.00	-2.53	0.01
Horizontal	476	1,154.28			
Vertical	1,770	1,382.68	880,015.50	-5.92	0.00
Deviated	1,066	1,477.97			
Horizontal	476	754.84	245,777.00	-1.71	0.09
Deviated	1,066	778.94			
Drilling Contractor					
A	1,058	677.81	137,208.50	-3.61	0.00
B	278	633.06			
A	1,058	643.02	120,058.00	-0.01	0.99
C	227	642.89			
A	1,058	682.72	162,106.00	-0.76	0.45
D	311	692.76			
A	1,058	694.18	163,266.00	-1.79	0.07
E	319	671.81			
B	278	245.72	29,529.00	-3.08	0.00
C	227	261.92			
B	278	282.52	39,759.50	-3.77	0.00
D	311	306.16			
B	278	293.60	42,838.50	-1.95	0.05
E	319	303.71			
C	227	267.34	34,808.00	-0.52	0.60

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Table E.4b – continued from previous page

Factor	N	MR	U	z	p
D	311	271.08			
C	227	278.44	35,084.00	-1.35	0.18
E	319	269.98			
D	311	322.89	47,307.00	-2.07	0.04
E	319	308.30			
No					
Well Design					
Vertical	1,086	970.11	463,300.00	-2.01	0.04
Horizontal	883	1,003.31			
Vertical	1,086	950.67	442,192.00	-3.83	0.00
Deviated	872	1,015.40			
Horizontal	883	862.30	371,123.50	-1.88	0.06
Deviated	872	893.90			
Well Type					
Gas	854	522.94	81,506.50	-4.22	0.00
Crude Bitumen	217	587.39			
Gas	854	826.20	340,492.50	-3.46	0.00
Crude Oil	852	880.86			
Crude Bitumen	217	557.08	87,650.50	-1.61	0.11
Crude Oil	852	529.38			
Drilling Contractor					
A	806	496.14	60,737.00	-3.27	0.00
B	168	446.03			
A	806	513.72	88,838.00	-0.69	0.49
C	225	524.16			
A	806	556.87	123,613.50	-0.03	0.97

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Table E.4b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
D	307	557.35			
A	806	547.35	105,703.50	-1.75	0.08
E	275	522.38			
B	168	184.14	16,740.00	-3.22	0.00
C	225	206.60			
B	168	222.10	23,116.50	-3.07	0.00
D	307	246.70			
B	168	214.37	21,817.50	-1.82	0.07
E	275	226.66			
C	225	269.32	33,903.00	-0.53	0.59
D	307	264.43			
C	225	259.10	29,003.00	-1.90	0.06
E	275	243.47			
D	307	297.98	40,224.00	-1.55	0.12
E	275	284.27			

E.5 Controlled Well Design

Table E.5a. Kruskal-Wallis nonparametric test summaries comparing well type and drilling contractor against leak occurrence controlling well design (n = number of townships, MR = mean rank, χ^2 = test statistic, df = degrees of freedom, p = significance level)

Vertical					
Factor	*N*	*MR*	χ^2	*df*	*p*
Well Type					
Gas	3,541	2,852.05	21.26	2	0.00
Crude Oil	1,462	2,882.17			
Crude Bitumen	673	2,672.36			
Total	5,676				
Drilling Contractor					
A	2,551	3,429.78	17.64	4	0.00
B	1,083	3,355.84			
C	1,222	3,302.37			
D	840	3,342.00			
E	1,046	3,350.03			
Total	6,742				
Horizontal					
Well Type					
Gas	517	751.93	7.62	2	0.02
Crude Oil	902	792.62			
Crude Bitumen	142	813.01			
Total	1,561				
Drilling Contractor					
A	825	901.62	10.60	4	0.03
B	27	797.57			
C	150	935.82			

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Table E.5a – continued from previous page

Factor	N	MR	χ^2	df	p
D	424	870.96			
E	350	865.56			
Total	1,776				
Deviated					
Well Type					
Gas	2,122	1,671.01	57.94	2	0.00
Crude Oil	1,124	1,774.54			
Crude Bitumen	205	2,029.09			
Total	3,451				
Drilling Contractor					
A	1,784	1,990.80	43.60	4	0.00
B	296	1,833.93			
C	536	1,927.51			
D	605	1,909.25			
E	629	1,797.31			
Total	3,850				

Table E.5b. Mann-Whitney nonparametric test summaries for the occurrence of leakage problems across Alberta controlling well design (n = number of townships, MR = mean rank, U = Mann-Whitney U test statistic, z = z-score, df = degrees of freedom, p = significance level).

Vertical					
Factor	*N*	*MR*	*U*	*z*	*p*
Well Type					
Gas	3,541	2,129.14	1,114,907.00	-4.31	0.00
Crude Bitumen	673	1,993.62			
Gas	3,541	2,493.90	2,559,799.00	-0.97	0.33
Crude Oil	1,462	2,521.61			
Crude Bitumen	673	1,015.74	456,790.50	-4.43	0.00
Crude Oil	1,462	1,092.06			
Drilling Contractor					
A	2,551	1,829.61	1,350,476.50	-2.06	0.04
B	1,083	1,788.98			
A	2,551	1,910.18	1,499,541.00	-3.75	0.00
C	1,222	1,838.62			
A	2,551	1,760.75	1,044,006.00	-2.16	0.03
D	840	1,663.36			
A	2,551	1,811.25	1,302,928.50	-2.14	0.03
E	1,046	1,769.13			
B	1,083	1,162.82	651,078.00	-1.47	0.14
C	1,222	1,144.30			
B	1,083	963.97	452,728.00	-0.78	0.71
D	840	959.46			
B	1,083	1,066.07	565,249.00	-0.17	0.86
E	1,046	1,063.89			
C	1,222	1,026.71	507,392.50	-0.99	0.32
Continued on next page					

Table E.5b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
D	840	1,038.46			
C	1,222	1,127.24	630,232.00	-1.27	0.20
E	1,046	1,142.98			
D	840	942.22	438,242.00	-0.20	0.84
E	1,046	944.53			
Drilling Issue					
Yes	1,770	1,389.00	891,203.50	-6.37	0.00
No	1,086	1,492.87			
Horizontal					
Well Type					
Gas	517	324.40	33,811.00	-2.25	0.02
Crude Bitumen	142	350.39			
Gas	517	686.54	221,036.00	-2.44	0.02
Crude Oil	902	723.45			
Crude Bitumen	142	534.12	62,392.00	-0.70	0.48
Crude Oil	902	520.67			
Drilling Contractor					
A	825	428.09	9,823.50	-1.67	0.10
B	27	377.83			
A	825	485.01	59,408.50	-1.22	0.22
C	150	504.44			
A	825	632.36	167,827.00	-1.65	0.10
D	424	610.68			
A	825	595.16	138,470.00	-1.82	0.07
E	350	571.13			
B	27	77.65	1,718.50	-1.94	0.05

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Table E.5b – continued from previous page

Factor	*N*	*MR*	*U*	*z*	*p*
C	150	91.04			
B D	27 424	208.48 227.12	5,251.00	-1.30	0.19
B E	27 350	175.61 190.03	4,363.50	-1.23	0.22
C D	150 424	302.76 282.10	29,511.50	-2.19	0.03
C E	150 350	264.07 244.68	24,214.00	-2.31	0.02
D E	424 350	388.56 386.21	73,750.00	-0.26	0.80
Drilling Issue Yes No	 476 883	 647.77 697.38	194,810.50	-3.52	0.00
Deviated					
Well Type Gas Crude Bitumen	 2,122 205	 1,142.49 1,386.63	171,866.50	-7.32	0.00
Gas Crude Oil	2,122 1,124	1,590.02 1,686.71	1,121,510.50	-4.12	0.00
Crude Bitumen Crude Oil	205 1,124	745.47 650.32	98,714.50	-4.30	0.00
Drilling Contractor A B	 1,784 296	 1,052.63 967.40	242,395.00	-3.44	0.00
A	1,784	1,169.14	462,690.50	-1.71	0.09
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Table E.5b – continued from previous page

Factor	N	MR	U	z	p
C	536	1,131.73			
A	1,784	1,207.77	516,887.00	-2.36	0.02
D	605	1,157.36			
A	1,784	1,238.76	504,407.50	-5.96	0.00
E	629	1,116.92			
B	296	403.78	75,562.00	-1.94	0.05
C	536	423.53			
B	296	439.37	86,096.50	-1.63	0.10
D	605	456.69			
B	296	468.89	91,350.00	-0.95	0.34
E	629	460.23			
C	536	573.79	160,643.00	-0.44	0.66
D	605	568.53			
C	536	603.97	157,333.50	-3.61	0.00
E	629	565.13			
D	605	635.67	179,280.00	-3.25	0.00
E	629	600.02			
Drilling Issue					
Yes	1,066	938.39	431,617.50	-4.14	0.00
No	872	1,007.53			

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