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Technology Roadmap to Improve Wellbore Integrity

SUMMARY REPORT



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This *Technology Roadmap to Improve Wellbore Integrity: Summary Report* brought together experts from industry, academia and government to examine wellbore integrity issues that may arise during the entire life cycle of a well.

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Executive Summary

Canada is a hydrocarbon superpower, with 10% of the world's proved crude oil reserves (3rd largest), and 1.2% of its natural gas reserves (15th) at the end of 2016. Even as the world transitions to less carbon-intensive energy sources, crude oil and natural gas will continue to provide 50% of the globe's energy needs for decades, including here in Canada. Improving the environmental performance of the upstream oil and gas sector while maintaining a competitive business environment is a priority for the Canadian oil and gas industry and government regulators. Wellbore leakage has received considerable attention over the past number of years for several reasons. The predominant leakage fluid is natural gas, which is largely composed of methane—a potent greenhouse gas (GHG). Federal and provincial governments, along with industry, have pledged to reduce methane emissions from the upstream oil and gas sector¹. According to Environment and Climate Change Canada, emissions from wellbore leakage were 7.2 megatonnes (Mt) CO₂ equivalent (CO₂e) in 2015, which was 4.3% of total emissions from the upstream sector^{2,3}. The Council of Canadian Academies 2014 report on shale gas development in Canada raised concern about the potential for potable groundwater contamination from wellbore leakage. Leakage is also a significant economic burden on industry and orphan well funds. The cost to remediate leaky wells ranges from tens of thousands of dollars for simple cases to millions for more complex ones. While the majority of wells in Canada don't leak⁴, the overall cost is still enormous given that nearly 580,000 wells were drilled between 1955 and 2017, and over a hundred thousand new wells will need to be drilled over the coming decades to meet projected hydrocarbon production increases. The National Energy Board predicts, for their reference case, that crude oil production will increase by 59% over 2016 levels by 2040, and of this, 75% will be from wells (i.e. non-mined oil sands).

Industry and government regulators in Canada have worked together to successfully improve wellbore integrity for decades. For example, the average daily emission rate of wellbore leakage for non-serious wells in Alberta has declined by 40% from 2000 levels to ~13 m³/day in 2016, and the median, or typical rate, is even less than this. In order to continue to improve the environmental and economic performance of the upstream oil and gas industry, Natural Resources Canada (NRCan), in collaboration with Canada's Wellbore Integrity and Abandonment Society (WIAS), launched a process to develop a *Technology Roadmap to Improve Wellbore Integrity*. The technology roadmap (TRM) brought together experts from industry, academia and government to examine wellbore integrity issues that may arise during the entire life cycle of a well. Considering

¹ Including a pledge by Alberta to reduce methane emissions by 45% compared to a 2010 Environment and Climate Change Canada (ECCC) baseline value.

² Data available at the time the report was written. ECCC estimated 2016 wellbore leakage emissions to be 7.1 MtCO₂e.

³ For comparison, methane emissions from solid waste management (i.e. landfills) were 22 MtCO₂e, and those from enteric fermentation (i.e. livestock emissions) were 25 MtCO₂e in 2015 (ECCC's 2017 National Inventory Report, 1999-2015, Part 3, Table A9-3).

⁴ Out of the ~440,000 wells drilled in Alberta, only ~5% have reported leakage.

that many operators have low incidences of wellbore leakage, existing technology and practices are very effective for the most part. Thus, the TRM captures best practices to address wellbore integrity issues where possible. For remaining knowledge and technology gaps, it provides recommendations on research and development (R&D) to address these. The TRM is not an exhaustive document as the subject is too large and complex to capture in one report. Rather, the intent of the TRM is to provide a high-level document that: (i) is a reference source; (ii) will facilitate action on specific wellbore integrity issues; and, (iii) will help guide R&D so that it is focused on topics that will have the most cost-effective environmental and economic impact.

For the TRM, the subject of wellbore leakage was broken into six topics: (i) *Magnitude and Impacts of Wellbore Leakage*; (ii) *Designing, Drilling and Construction*; (iii) *Leak Source Identification*; (iv) *Remediation Strategies*; (v) *Abandonments*; and, (vi) *Industry Knowledge, Best Practices and Regulations*. Reports were commissioned for each and were produced by a cross-section from academia and industry. Draft reports were presented at an open workshop in 2016 and revised based on feedback and expert reviews. The TRM is a high-level summary of these topic-specific reports and readers are encouraged to consult the individual reports for more detail⁵. The following presents some highlights from each report.

Magnitude and Impacts of Wellbore Leakage: This report focused on Alberta as it has the majority of Canada's hydrocarbon wells and is the most studied. There are multiple sources and emitters of methane to the atmosphere and shallow subsurface—both from the upstream oil and gas sector and other industrial sectors, as well as natural sources. The impacts are agnostic of the source. Thus, it is imperative to understand their relative contributions and avoidance/mitigation costs in order to develop the most cost-effective methane reduction strategies.

Beginning in the 1980s industry and regulators in Alberta began to reduce the rate of well integrity issues. As of 2016, 5% of the 440,000 wells drilled in Alberta developed leakage. Emissions from wellbore leakage have declined since 2008, even as the number of wells has increased, and was, according to the Alberta Energy Regulator, 1.56 MtCO₂e in 2016. About 30% of this was from wells classified as serious (vent flow greater than 300 m³/day, amongst other criteria), which must be immediately remediated; the remainder is from non-serious wells (which must be remediated, at latest, at abandonment), with an average rate of 13.2 m³/day, although the median, or typical rate, is less. Of the 10,326 leaking wells, 96.7% were nonserious.

The risk of wellbore leakage resulting in pervasive contamination of soil and potable groundwater in Canada is considered low: only a few instances of aquifer contamination have been identified in spite of the hundreds of thousands of wells drilled. In Alberta only 0.66% of wells leaked to the subsurface (termed gas migration [GM]), and GM effects are predominantly localized around the well. In light of other sources of methane in the subsurface and the considered low risk of groundwater contamination, it is recommended that R&D be conducted to determine if acceptable wellbore leakage

⁵ The topic-specific reports can be accessed through the Wellbore Integrity TRM page, which is found on NRCan's TRM webpage at: <http://www.nrcan.gc.ca/energy/offices-labs/canmet/5765>

rates can be established such that soil and groundwater use is not impaired. Such studies could inform the development of risk assessment-based approaches to wellbore remediation for non-serious wells. Not requiring remediation of all non-serious leaks at abandonment in instances where the risks and impacts are considered acceptable will reduce the cost of abandonments. This will allow limited resources to be deployed against other environmental problems, and will facilitate the abandonment of uneconomic wells for owners, who may leave wells in a suspended state as remediation costs may be too onerous to abandon them, and provincial orphan well funds.

Designing, Drilling and Construction: How a well is designed, drilled and constructed is critical in determining the likelihood of leakage over its lifetime, including post-abandonment. Leakage occurs when pathways develop in the cement that is used to seal the annular space both between casings, and the outermost casing and borehole face, and fluids invade and migrate upwards in these. Leakage also may occur when fluids migrate from inside to outside the casing due to corrosion of the casing or leaky connections. The failure of annulus seals is primarily the result of poor mud displacement during cementing, gas migration into cement during setting, microannulus or stress crack formation during operation, or autogenous shrinkage during cement hydration leading to the formation of a micro-annulus.

Drilling oil and gas wells remains a challenging task considering their requirements (e.g. depth, length, pathway), environment (pressure, temperature, fluid composition), and operating conditions (e.g. cyclic high pressure and temperature for fracked and thermal heavy/oil sands wells). But, many operators have low incidence of wellbore leakage as a result of: considering a well's complete life cycle during design; following best practices (published and in-house); and spending extra time and money up front... in other words, doing things right in the first place. Thus, significant reductions in wellbore leakage can be achieved tomorrow by getting more operators to behave like industry-leading ones. Wellbore integrity may be improved to an even greater extent by conducting R&D on advanced cement formulations and casing materials (e.g. expandable packers) to improve their resiliency under fluctuating and extreme conditions, and their long-term durability. It is also recommended that R&D be conducted to validate the efficacy, safety and cost effectiveness of operational practices employed during drilling and construction which have shown the potential to reduce wellbore leakage, but which well owners and service companies are reluctant to employ because of their novelty or perceived risk of damaging a well. For example, determining if pipe rotation overly fatigues well casing.

Leak Source Identification: In order to fix a leak, you first need to determine the depth (and thus formation) at which it is originating so that an effective seal can be emplaced at the leak source, or in some cases, at an overlying competent caprock. Source formations are commonly thin, uneconomic gas-bearing strata that were bypassed during drilling on the way to deeper pay zones. There are three types of methods used to identify sources: (i) acoustic energy measurements; (ii) carbon isotopes; and, (iii) formation evaluation. Regulations don't specify which to use, but best practice is to employ the application of all.

Acoustic tools listen for the sound produced as fluid flows in the annulus, and pinpoint the depth of the source. Advances in acoustic energy measurements to improve source identification and magnitude include: spectral noise logging; geophone noise surveys that employ an array of sensors downhole; and fibre optic digital acoustic sensing. Geological formations have a distinct ratio of ^{13}C to ^{12}C (an isotopic fingerprint). By comparing the ratio from a sample of leakage gas against those from samples collected from producing formations as the well (or nearby wells) was/were drilled, it is possible to identify the source. Wells are variably logged after they are drilled and/or cased in order to determine the lithology and formation properties (e.g. fluid composition, porosity). These help inform source identification by indicating parameters such as gas-bearing formations, caprocks and zones of poor cement quality. A lack of standardized data/sample acquisition and interpretation is a major barrier to successful source identification. It is recommended that these be developed using existing knowledge and that R&D be conducted to address gaps (e.g. effect of heat from thermal wells on isotopic ratio). Developing a high-quality comprehensive isotopic fingerprint database with samples from all producing horizons from hydrocarbon producing regions would be extremely helpful.

Remediation Strategies: Regulations governing the fixing of leaks (i.e. remediation or intervention) are objective-based because the variety of scenarios and remediation technologies preclude the development of proscriptive-based regulations. Most jurisdictions allow for some leakage during a well's lifetime, but require complete isolation at abandonment. The remediation process is: (1) identify the source of the leak (as previously discussed); (2) develop access to the source/leakage pathways; (3) seal the leak; and, (4) verify success. The most common method is "squeeze placement," a method in which the casing is perforated at the leak source and a sealant, most commonly Portland cement, is forced into the leakage pathways. In addition to cement, there are a variety of other sealants (e.g. resins, metal alloys, pressure-activated sealants, and more) that have (or claim to have) better sealing properties and durability. The success rate of the cement squeeze method can be low (50% in some regions). The cost of cement squeeze remediations can range from tens of thousands to millions of dollars. Inadequate leak source identification and poor communication with leakage pathways are two of the primary reasons for lack of success (for any method), but cement properties may also contribute (e.g. particle size can be a barrier to entry for small channels).

Given the number of remediations performed, there is considerable data on what does and doesn't work under given conditions; however, this information is not widely shared amongst companies, particularly for failures. Improving data sharing on remediation practices and results is recommended. Such data would help inform the development of a comprehensive *Industry Recommended Practice* (IRP), which would support regulations that are (by design) lacking in technical content. Such an IRP should include topics like a description of the various sealing materials and methods available, and decision-making tools (e.g. flow charts) to guide their selection considering the well's conditions. Lab- and field-based independent evaluation of various remediation materials and methods (particularly novel ones that have not been applied in the field

much or at all) should be pursued and supported by the development of protocols and methods to evaluate their efficacy in a consistent manner.

Abandonments: Dry holes or wells that are no longer economic are sealed during the abandonment process in order to prevent the migration of fluids within the wellbore and near-wellbore region. The basic technology associated with plugging and abandoning wells has not changed significantly since the 1970s. The basic steps are: (1) test for surface casing vent flow (SCVF)/GM and remediate if present; (2) prepare the wellbore for abandonment; (3) plug the well (commonly by emplacing ~ 8 m of cement on top of a mechanical bridge plug); and, (4) cut and cap the well. Abandoned wells develop leaks either because of inadequate sealing of the (usually) cemented annulus and/or inadequate sealing within the casing. Since monitoring began in Alberta in 1910, 7% of the 25,000 wells that have developed leakage were of the abandoned well type.

The methods used to remediate annulus leaks as discussed above are applicable to both producing wells and those to be abandoned. With respect to plugging wells, the predominant dump-bailing method was analyzed in a small but informative study in Alberta, and the results indicated that it may be ineffective as the cement plug quality was extremely poor in about half the wells. In addition to dump-bailing, there are a number of other technologies, of varying degrees of development and use, which may offer better performance. In terms of more conventional ones, it is recommended that the balanced plug method, in which cement is emplaced between two packers and develops superior strength, replace the dump-bailing method except in low-risk wells, and that longer (~100 m) cement plugs be used in dump-bailing. Removing a section of casing and annular cement at a caprock boundary to facilitate the improved emplacement of a sealing material has been suggested to be a standard abandonment practice. And bentonite-based plugging materials, which the nuclear waste industry has investigated as a well-plugging material, should be considered. More novel technologies include thermal sealing (melting casing, cement and rock to make a seal across a caprock), molten material plugs (low-melting point metals and salts), and casing expansion. As has been noted for the other wellbore topics, a major challenge with the deployment of novel abandonment technologies is a lack of familiarity and/or confidence by the industry and regulators in their performance, which in turn is driven by a lack of independent testing. Thus, it is again recommended that testing standards and methods be developed against which technologies can be evaluated (where feasible), and that independent field-based R&D be supported, conducted and made public.

Industry Knowledge, Best Practices and Regulations: Government regulations prescribe minimum requirements governing oil and gas wells in Canada. Many oil and gas exploration and production companies go above and beyond that required by regulations by following best practices, and in the process achieve fewer instances of wellbore leakage. Best practices (commonly termed Industry Recommended Practices in the Canadian upstream oil and gas industry) play an important supporting role in the regulatory environment. Best practices can, and should, be more descriptive, and can cover more situations and descriptions than regulations. Best practices are more easily updated than regulations and allow for evolution as additional knowledge and

technology become available. Research and development is commonly led by service and technology companies, as opposed to exploration and production companies, as wellbore remediation is a source of revenue. As Canada is a mature basin, there are multiple Canadian organizations that focus entirely or partly on wellbore leakage and abandonment, including the Wellbore Integrity and Abandonment Society (WIA Society).

There are several barriers to the development and use of best practices to reduce wellbore leakage. Sharing of industry knowledge, which underpins best practices, needs to be improved to increase the understanding of what works. R&D used to develop industry knowledge and support best practice development needs to be conducted in a scientifically rigorous manner, instead of the typical trial and error approach, in order to pinpoint the mechanisms that are actually responsible for improved wellbore integrity. Such an approach will provide confidence to users, regulators and the public, that they are effective in reducing wellbore leakage. Scientifically rigorous wellbore integrity data should be considered as a valuable source of information to improve wellbore regulations.

Other general recommendations not covered in the preceding chapters include: (1) Developing regulatory consistency across the provinces; (2) Improving knowledge amongst the oil and gas R&D community of funding options (e.g. tax credits, grants, subsidies) to accelerate wellbore integrity R&D; (3) Increasing awareness in industry of cost savings to be had from *Doing it right the first time*; (4) Training new technical employees in reverse of the typical order to start their careers working on remediations and abandonments, ensuring technical employees understand the costs and causes of leakage so that they design and construct better wells; (5) Promoting multi-well abandonment campaigns; and, (6) Promoting long-term abandonment planning with adequate funding.

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<i>Improving our Understanding of the Magnitude and Impacts of Wellbore Leakage</i>	Kirk Osadetz (Carbon Management Canada) and Dr. Casey Hubert (University of Calgary)
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<i>Improving Well Construction Materials and Procedures to Reduce Wellbore Leakage</i>	Christian Hamuli and Theresa Watson (T.L. Watson and Associates Inc.), and Dean Casorso and David Ewen (Fire Creek Resources Ltd.)
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<i>Improving Wellbore Leakage Source Identification to Increase Remedial Intervention Success</i>	Rose McPherson and Paul Pavlakos (Weatherford Canada)
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<i>Intervention Strategies to Increase Wellbore Leakage Remediation Success Rates</i>	Jonathan Heseltine and Todd A. Zahacy (C-FER Technologies)
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<i>Improving Abandonment Processes</i>	Robert Walsh and Dru Heagle (Geofirma Engineering Ltd.)
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<i>Improving Industry Knowledge, Best Practices and Regulations to Reduce Wellbore Leakage</i>	Jay Williams (Wellbore Integrity and Abandonment Society)
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Introduction

Canada's history of crude oil and natural gas production began in Lambton County, southwestern Ontario, back in 1859 when James Miller Williams drilled a well specifically looking for crude oil after having come across it in a shallow water well dug a few years prior. This was followed by discoveries and production in nearly every other Canadian province and territory. Between 1955 and 2017, 577,207 crude oil and natural gas wells, for a total length of ~720,000 km, were drilled in Canada, of which 71% were in Alberta (Canadian Association of Petroleum Producers, 2017).

Today, our combined conventional and unconventional crude oil and natural gas resources make us a hydrocarbon energy superpower. British Petroleum's 2017 *Statistical Review of World Energy* (2017) states that Canada has 10% of the world's proved crude oil reserves, which is the third largest, and 1.2% of the proved natural gas reserves, which ranks us 15th; additionally, we were the fourth largest crude oil producer and fifth largest natural gas producer in 2017.

The hydrocarbon industry in Canada is a major economic force that is active in twelve of thirteen provinces and territories: in 2015, it contributed \$19 billion to government revenues, provided 533,000 jobs across the country in 2017 (Canadian Association of Petroleum Producers, 2018), and made up 6.5% of our GDP in the same year (Statistics Canada, 2018).

Hydrocarbons will continue to play an important role as the world transitions to a less carbon-intensive energy supply. British Petroleum's 2018 *World Energy Outlook* (2018) projects that global energy demand will grow by about a third by 2040 to 544,284 petajoules. Natural gas use is expected to grow and meet about 25% of this need; oil grows at a slower rate, plateauing near 2040, but will still provide about 25% of our needs. In Canada, the National Energy Board, in its 2017 energy supply and demand projections, projects for its Reference Case that by 2040 we will require 14,170 petajoules, which is a 6.4% increase over 2016⁶ (National Energy Board, 2017a; **Figure 1.1**). On the supply side, it projects that crude oil production in Canada will increase by 59% over 2016 levels by 2040, to 6.3 million barrels per day (MMb/d). Of this, 4.5 MMb/d are from oil sands production and 2.9 MMb/d are from in situ production. Natural gas production is also expected to increase from 2016 levels, going from 431 million cubic metres per day to 480 million cubic metres per day as gas prices rise.

According to the National Energy Board's Reference Case, ~112,000 new wells are estimated to be drilled between 2018 and 2040 to meet production demands from conventional and tight and shale oil reservoirs (Appendix A.2.2 of National Energy Board, 2017b), and ~29,500 to meet natural gas production (Appendix B2.1 of National Energy Board, 2017c.). No estimates for in situ oil sands production are made.

⁶ The Reference Case is based on a current economic outlook, a moderate view of energy prices, and climate and energy policies announced at the time of analysis.

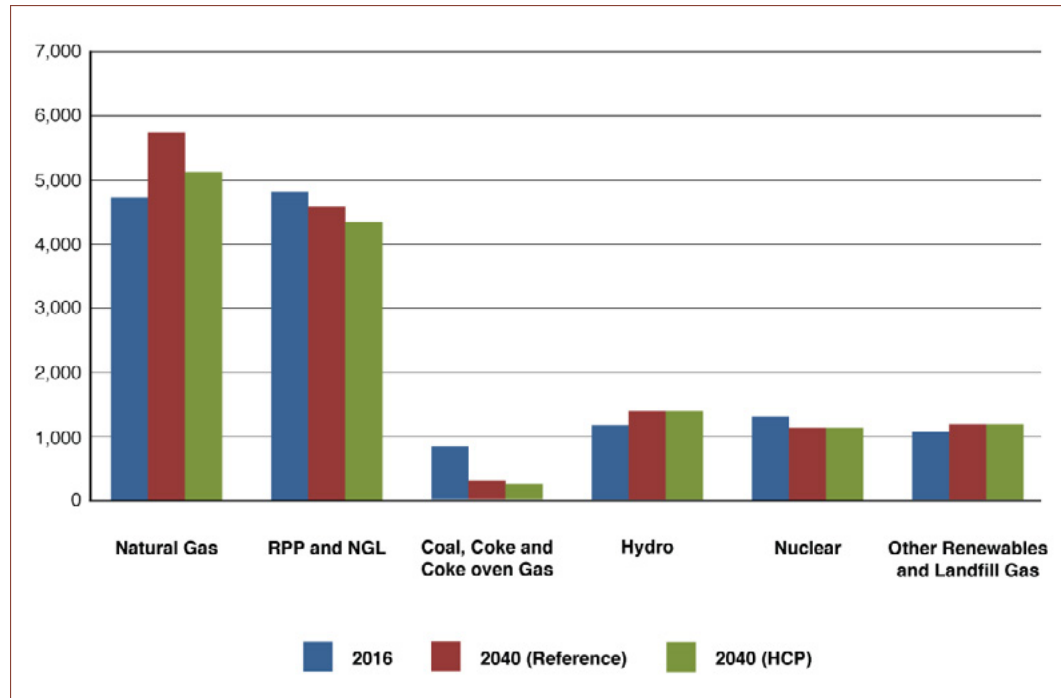


Figure 1.1 Primary energy demand, reference and high carbon price (HCP) cases (National Energy Board, 2017a).

The technology used to drill and construct wells has advanced considerably since 1859, but the objectives remain the same: prevent the well from collapsing and control the flow of fluids. A minor percentage of older wells leak because of material issues, and less robust practices and regulations. However, even today, a small percentage of new wells continue to experience wellbore leakage, which we define as the unintended migration of fluids within or along the wellbore to the shallow subsurface and/or atmosphere. Natural gas, which is mostly methane, is the predominant leakage fluid because it is buoyant and drives to the surface; other fluids include saline water and oil. Drilling and constructing wells remains a complex task, and is even more so today as deeper reservoirs are tapped, kilometre-long horizontal wells are used, and wells are exposed to extreme heat and pressure during fracking and thermal oil and gas stimulation processes.

Concerted regulatory and industrial efforts began to reduce the rate of well integrity issues in the mid-1980s (Watson and Bachu, 2009). However, wellbore leakage has been the focus of considerable attention over the past number of years for several reasons, and these belie the importance of continuing to strive to improve wellbore integrity. Methane is a potent greenhouse gas (GHG), and both the federal and provincial government(s) and industry have committed to reducing methane emissions from the upstream oil and gas sector⁷. Concern about the potential for groundwater

⁷ For example, the recent Alberta Climate Change Advisory Panel report and Provincial Strategy (Leach et al., 2015); the Federal Government's proposed 40-45% reduction strategy for methane emissions from the oil and gas sector relative to 2012 levels (Environment and Climate Change Canada, 2017); and the consortium of the oil and gas producer members of the Oil and Gas Climate Initiative (oilandgasclimateinitiative.com).

contamination from wellbore leakage has also been raised, including in the Council of Canadian Academies Expert Panel's report on *Environmental Impacts of Shale Gas Extraction in Canada* (2014). There are also strong economic reasons to improve wellbore integrity. Remediation⁸ costs and loss of production are costing the industry an average of \$150,000 per well in some circumstances, although they can be much higher as evidenced by a well in British Columbia that cost \$8 million to repair (Dusseault et al., 2014). Remediation costs are especially burdensome for orphan well funds that are managed by the provinces (CBC News, 2018). Leaking wells and older abandoned wells may also inhibit or drive up the cost of developing heavy oil and bitumen reservoirs. Such wells may not be able to tolerate the thermal stress that they are exposed to during the use of steam-driven processes for extracting heavy oil and bitumen, and may communicate oil to the surface, which may either preclude further development or require expensive remediations (Munro, 2014a). Leaking wells are also being discovered as new suburbs are built in previously rural land. Remediation costs for such cases can be large, and activities severely disruptive to home owners, such as for the case near Calmar, just outside of Edmonton, for which a house had to be purchased and demolished to access the well and others relocated (Munro, 2014b).

Both the upstream oil and gas industry, and the federal and provincial government(s) in Canada recognize the need to minimize the environmental impact of crude oil and natural gas development while maintaining a globally competitive jurisdiction. Improving wellbore integrity by constructing wells that are less likely to leak in the first place, and by improving the success and reducing the cost of remediations and abandonments, will help address both of these challenges.

Advances in well construction materials and processes, and our understanding of the impacts and magnitude of wellbore leakage, continue to be made by industry, academia and regulators working both independently and collaboratively. In Canada, there are a number of organizations that are focused solely or partly on wellbore leakage, including the Wellbore Integrity and Abandonment Society (WIAS, formerly the Canadian Society for Gas Migration); the Western Regulators Forum, which brings together oil and gas regulators from British Columbia, Alberta and Saskatchewan; Enform's Drilling and Completions Committee (DACC); and, the Canadian Standards Association (CSA).

In order to support and guide efforts to improve wellbore integrity, the federal government's Department of Natural Resources (NRCan) partnered with the WIA Society to develop a *Technology Roadmap to Improve Wellbore Integrity*. The focus of the technology roadmap (TRM) is on methane because it is the predominant leakage fluid, and because of the focus on reducing GHG emissions; however, improvements to wellbore integrity will serve to reduce leakage of all fluid types. While crude oil and natural gas production is largely the domain of provinces and territories, working with partners to address wellbore leakage fits within NRCan's mandate "to enhance the responsible development and use of Canada's natural resources and the competitiveness of

⁸ Remediation refers to fixing leaks, and not cleaning up contaminated soil and groundwater, unless otherwise indicated.

Canada's natural resources products." The WIA Society is an ideal partner: the Society's mission is to be the foremost community dedicated to designing, maintaining and sustaining wellbore integrity. The society is collaborative as it is the industry group with a membership comprised of regulators, academia, oil and gas exploration and production companies, service and technology companies, and abandonment consulting specialists.

Technology roadmaps are a strategic planning exercise used by industry and government to bring together stakeholders to identify barriers to a desired future state and formulate potential pathways to overcome them. NRCAN has produced a number of TRMs⁹. The focus of this TRM was to identify material- and process-related issues that negatively impact wellbore integrity; determine which of these can be addressed using known best practices; and suggest research and development (R&D) to address those that can't. The scope of the TRM covers the lifespan of a well, from wellbore design and construction, leakage identification and remediation, and ultimately, abandonment. Since there are a number of operators with very few wellbore integrity problems, the TRM also focussed on determining how the sector can better gather, share and promote the use of best practices.

Lastly, the TRM focussed on the issue of wellbore leakage magnitude and impacts, both environmental and human health, including what knowledge gaps exist and how to address them. While industry should continue to strive to construct wells that are less likely to leak, it is also reasonable to pose the contentious question of: should all wells with small leaks have to be remediated? Being cognizant of the reality that funds spent improving environmental performance don't always provide an economic return, that Canada's oil and gas exploration and production companies compete for investment in a global environment, and that orphan well funds represent a significant cost to the public, it is imperative to focus on practices that will provide the most cost-effective beneficial environmental impacts.

The subject of wellbore integrity is large and diverse, incorporating a number of engineering and scientific disciplines. The intent of the wellbore leakage TRM was not to create an exhaustive document, but rather to provide a high-level assessment of the issues and potential solutions. It is intended to foment and facilitate more detailed discussions on developing solutions, and to guide R&D so that it is focussed on solutions that will have the largest positive economic and environmental impact. A brief summary of the TRM process follows.

Chapter 2 provides a primer on how wells are drilled and how they develop leaks. Chapter 3 covers the magnitude and impacts of wellbore leakage. Chapters 4–7 cover wellbore construction, leakage identification, wellbore remediation, and abandonment. The last chapter discusses gathering, sharing, and promoting the use of best practices.

⁹ For full list visit: <http://www.nrcan.gc.ca/energy/offices-labs/canmet/5765>.

While the focus of this TRM is on oil and gas wells, the findings and recommendations may be applicable to other industries that use wells, such as CO₂ storage, nuclear and other waste disposal, and geothermal energy. Conversely, some best practices from some of these industries may improve wellbore integrity in the oil and gas industry. Some authors knowledgeable of these other fields have captured this information in their reports. Sharing information and practices both within and with other industries that use wells will serve to improve wellbore integrity for all.

1.1 Production of the Technology Roadmap to Improve Wellbore Integrity

The vast topic of wellbore leakage was broken down into six smaller topics to facilitate the production of the TRM:

- ▶ What are the frequency, magnitude and effects of wellbore leakage?
- ▶ How can wells be better constructed to avoid or minimize leakage?
- ▶ How can leaks be better detected?
- ▶ How can the success rate of remediations be improved and costs be reduced?
- ▶ How can abandonments be improved to decrease the frequency and magnitude of leaks?
- ▶ How can the gathering, sharing and implementation of industry best practices be improved?

Reports were commissioned for each topic. Authors were from industry and academia. For each report, a brief summary of current knowledge and/or practices and regulations was presented, followed by a discussion of issues that adversely impact wellbore performance. Each report concluded with recommendations on how they can be addressed using current knowledge and/or practices, and how remaining knowledge and technology gaps may be addressed with R&D. Draft reports were presented at an open workshop that was hosted by the Wellbore Integrity and Abandonment Society in Calgary in 2016, and which was attended by more than 80 people from industry, regulatory bodies and academia. Draft reports underwent a rigorous review process. In addition to feedback received at the workshop, each draft report was also reviewed by a volunteer-based Technical Advisory Committee that consisted of specialists in each subject area. A final third-party review of each revised report was contracted.

It needs to be noted that wellbore integrity is not a settled science... hence the need for a TRM. While much information about wellbore integrity is published, and organizations like the WIAS and others strive to capture and share information on what does and doesn't work, there are still uncertainties and differences of opinion about the efficacy of materials and practices, and where they are or aren't effective. Some of the answers may be known but are kept in-house and used as a competitive business advantage. For others, the studies just haven't been done yet, or the results may be in question because the study wasn't done or verified by an independent party.

The authors of the topic reports have attempted to deal with this issue by providing a balanced approach in which they emphasized or reported only data and information that was substantiated. However, contrary opinions supported by less published and/or anecdotal evidence is also reported where it was considered reasonable. Indeed, reasonable contrary opinions are valuable in that they highlight uncertainties that may warrant further investigation.

To provide a more user-friendly document, the topic reports have been summarized into this *Technology Roadmap to Reduce Wellbore Leakage* summary report.

While the subject of wellbore integrity was broken into five technical topics, and one on sharing information, there are not firm boundaries between these subjects. Thus, it is inevitable that there is overlap between the reports. In writing the summary report, the bulk of information on a given topic came from its respective report; however, information was pulled from other reports where appropriate. The individual reports are publicly available from NRCan's TRM website¹⁰ and those interested in more detail should consult them.

¹⁰ The topic-specific reports can be accessed through the Wellbore Integrity TRM page, which is found on NRCan's TRM webpage at: <http://www.nrcan.gc.ca/energy/offices-labs/canmet/5765>



Why and How do Wells Leak? A Primer

This chapter provides a primer on how wells are constructed and how leaks develop. These topics are covered in much more detail in Chapters 4–7. However, this overview will aid in understanding both these chapters and the preceding chapter on the magnitude and impacts of wellbore leakage (Chapter 3).

When wells are drilled through fluid-bearing formations, they create a new pathway, allowing these fluids, particularly natural gas, which is more buoyant than saline water or crude oil, to flow vertically across previously impervious formations. Hydrocarbon wells are constructed to control and collect this flow, while preventing vertical crossflow between formations, protecting freshwater aquifers and avoiding atmospheric emissions of gas. For a minority of wells, failures occur during some stage of the well's life, allowing fluids to migrate outside of the casing.

To understand the causes and mechanism of wellbore leakage in hydrocarbon wells, it is important to review how they are constructed. Well construction consists in sequentially drilling a hole, setting casing and cementing it in place for successive planned boreholes. Cement is placed in the annulus—the space between the casing and the wall of the borehole, or between the casing and the previous casing in a sequence of nested casings. Problems that contribute to wellbore leakage may occur at any of these phases. The number of casings required is determined based on the total depth, anticipated formation pressures, formation stability (or compatibility with drilling fluids) and cost. As illustrated in **Figure 2.1**, a typical succession of hole and casing size for a deep well consists of a conductor, surface, intermediate and production casing. For shallower wells, the number of casing stages is reduced.

Fundamentally, wellbore leakage into aquifers or the atmosphere requires a source, a pathway and a driving force. The source is typically a sufficiently permeable hydrocarbon-bearing unit, while the driving force requirement is supplied by buoyancy and reservoir pressure. Natural gas is the principle leakage fluid because it has a much lower density, and thus greater buoyancy force, than crude oil or saline water. There are numerous mechanisms and pathways that may contribute to the wellbore leakage problem, but it is most often attributed to the failure of cement sheaths (annulus cement) or cement plugs (in abandoned wells) to provide isolation. Failure of the cement sheath to provide zonal isolation can result in annular pressure or flow. Common names for this in Canada include Surface Casing Vent Flow (SCVF), if within the surface casing annulus, or Gas Migration (GM), if outside of the outer casing string. In other jurisdictions, the general term Sustained Casing Pressure (SCP) or Annular Pressure Buildup (APB) are often used, which may refer to any annulus. In SCVF, natural gas escapes directly from the well to the atmosphere via the surface casing vent (SCV). In Western Canada, SCVs must be left open. This is in contrast to jurisdictions in the United States where they must be kept closed. However, closing the SCV allows gas pressure to build up in the annulus; the pressure can continue to build until it is greater than the pressure in the surrounding shallow aquifer and gas flows into it.

In GM, since the natural gas is not confined within the outer casing string, it travels up the cracks or gaps in the cement, sealing the annular space between the borehole and outer casing string, and eventually into the surrounding rock, soil and groundwater in the shallow subsurface. From there it may migrate to the atmosphere.

When SCVF/GM events are identified, depending on the leakage characteristics and the operational or health/safety/environment (HSE) risks, investigation and remediation may be required. Remediation must be conducted prior to permanent well abandonment.

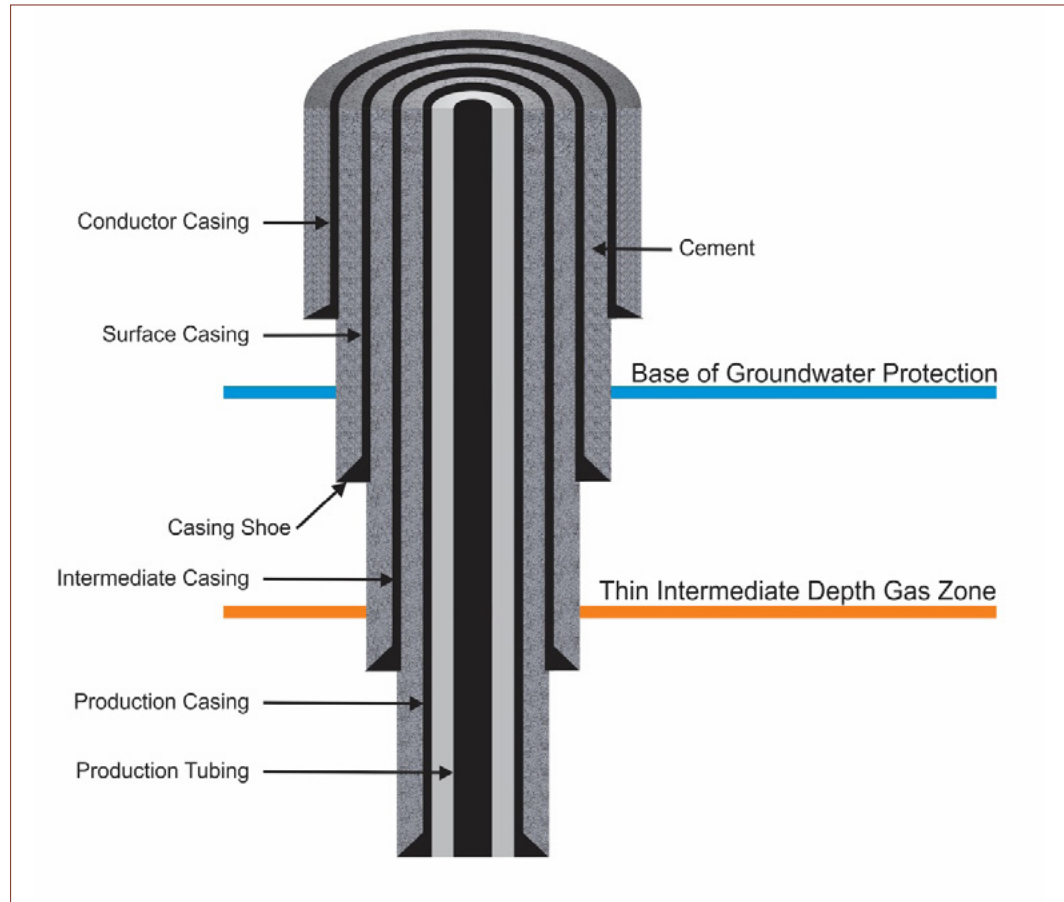


Figure 2.1 Typical well casing diagram.

Wellbore integrity can be compromised by defective well construction, or as a result of chemical and mechanical stresses (pressure, temperature) that damage the well during the operational or abandonment phases (Carrol, 2016). During drilling and cementing, problems that may lead to poor cement sheath and compromised casing integrity include thread leaks between casing joints, fluid losses/low cement top, poor cement quality, development of mud or gas channels in the cement, cement shrinkage, inadequate filter cake removal, formation damage during drilling, or fractured cement (Carrol, 2016). These concerns can generally be addressed with improved drilling and cementing practices during the well construction phase.

Leakage can also result from various events over the life of the well, often associated with mechanical disturbances or pressure and temperature changes during production, injection, stimulation or change out of wellbore fluids. These circumstances may cause cement sheath cracking or cement debonding and micro-annulus formation. During the operational (post-completion) phase, defects in well construction may develop into problems such as dissolution-induced cement defects, formation of microannuli, chemical degradation of cement, development of fractures in the annulus cement, and casing and tubular corrosion. These types of failure may be addressed through management of wellbore conditions (e.g. temperature and pressure) and the chemical and mechanical properties of the cement (e.g. Young's modulus, and tensile, shear and bond strengths) (Watson et al., 2002). Potential leakage pathways are illustrated in **Figure 2.2**.

Natural gas leaking through a wellbore may originate from the target reservoir depth, or most often from one or more thin, shallow- to intermediate-depth, non-commercial natural gas-bearing formations. Gases from these sources may be either of biogenic or thermogenic origin, or a combination of both (Dusseault et al., 2014). Isotopic analysis of leaking hydrocarbons in the Western Canadian Sedimentary Basin showed that leaks are typically from a shallow to intermediate source rather than the target reservoir (Rich et al., 1995; Rowe and Muehlenbachs, 1999; Slater, 2010; Tilley and Muehlenbachs, 2011). This agrees with the findings of Hammond (2016) where shallower but unproductive natural gas-bearing zones were identified as the source of methane in groundwater.

Producing zones are often sealed with higher quality cement in a wellbore (Watson and Bachu, 2009; Dusseault and Jackson, 2014). The cement adjacent to the reservoirs is generally emplaced under high hydrostatic pressure (before setting), exceeding pore pressures in the surrounding bedrock. This may promote loss of water to adjacent formations, resulting in denser cement slurry and an improved seal (Dusseault and Jackson, 2014), and inhibit gas influx during setting (at least initially). The opposite is true of intermediate and shallow depth intervals, which may be sealed with lower quality lead cement containing filler additives, which do not always generate good primary seals (Watson and Bachu, 2008; Dusseault and Jackson, 2014). However, this is not the case for thermal wells or many unconventional wells (Zahacy, personal communication, 2018). Natural gas in the intermediate or shallow formations can seep into the annulus surrounding the casing because of the poor seal the cement provides between the borehole wall and the casing. Once in the annular space, it may migrate upwards through pathways in the cement seal and potentially through permeable formations or small fractures in formations adjacent to the wellbore.

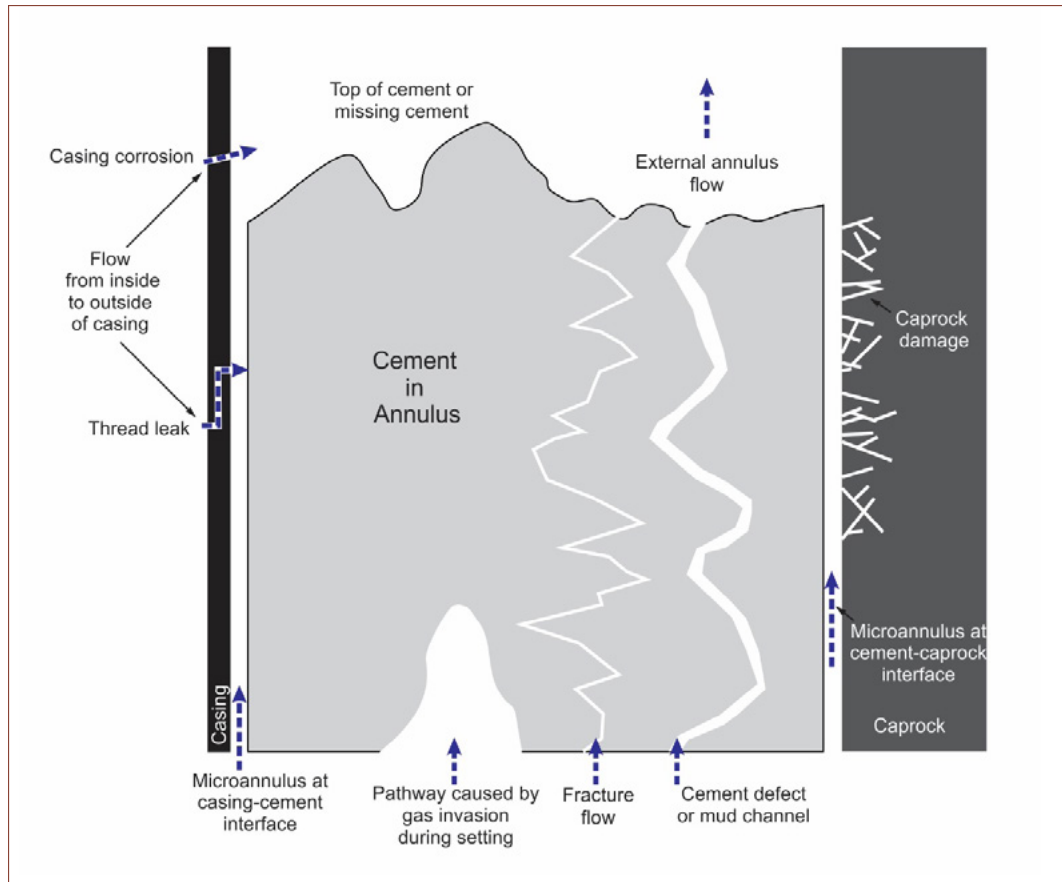


Figure 2.2 Possible leakage pathways in the annulus of a hydrocarbon well. (Based on Viswanathan et al. 2008).



Magnitude and Impacts of Wellbore Leakage

The objective of resource development, including hydrocarbon production, is to create the conditions by which a resource can be profitably developed while minimizing the environmental, human health and safety impacts to an acceptable degree. Within the upstream oil and gas sector there are a number of sources of potential impact. The impact depends on the source properties (e.g. what is the pollutant? How much and where is it released to?), and the receptors (e.g. humans, vegetation, atmosphere) and pathways to them (e.g. to atmosphere, groundwater). When devising acceptable impact standards and mitigation strategies, it is important to take a big picture view that considers other sources, both within and outside an industrial sector, that emit the same pollutant and that have similar receptors and pathways. In this way, the environment, and human health and safety will be protected in the most cost-effective and impactful manner.

This chapter discusses the magnitude and impacts of wellbore leakage; it is a summary of the *Improving Our Understanding of the Magnitude and Impacts of Wellbore Leakage* report written by Kirk Osadetz (Carbon Management Canada) and Dr. Casey Hubert (University of Calgary). It focuses on methane because that is the principal wellbore leakage substance as described in Chapter 1. A brief background on the origin of methane and migration pathways is discussed, followed by a summary of the current state of knowledge about the magnitude and impacts of wellbore leakage. The chapter closes with recommendations to address knowledge gaps.

3.1 Background

Crude oil and natural gas consist of hydrocarbon compounds, the simplest of which is methane (CH_4). Hydrocarbon compounds can result from both natural and anthropogenic processes at the earth's surface and below it, at a wide range of depths, and from a variety of sources (e.g. cow belching, natural hydrocarbon seeps, wellbores with leakage).

Organic and inorganic materials accumulate over geologic time spans. As this material is progressively buried, it is exposed to increasing heat and pressure; non-burial-related tectonic processes may also play a role. Crude oil and natural gas are generated, provided the precursor organic material is exposed to the appropriate temperature and pressure for a suitable period of time. This process is referred to as thermogenic generation (Hunt, 1979). Crude oil and natural gas are more buoyant than water, especially saline water, and have a natural tendency to migrate upwards through porous rock, open fractures, and by diffusion. They continue to migrate until they come up against geological features such as impermeable caprocks, below which they accumulate as oil and gas deposits. Otherwise, they continue to migrate to the surface (Tissot and Welte, 1984). Leaky hydrocarbon wells are also conduits for uncontrolled migration of crude oil, and more commonly, natural gas.

Closer to the earth's surface, and under anaerobic conditions below the surface of the water table, biogenic processes can produce methane (e.g. Cheung and Mayer, 2009), and possibly heavier hydrocarbons. Near the surface of the water table, and above it in the unsaturated zone, methane can be converted to CO₂ by methanotrophic bacteria.

The molecular composition of natural gas and the isotopic ratio of its carbon constituents are indicative of the process by which it was generated, and thus, the depth at which it was formed.

There are two types of biogenic methane production. Primary production results from the microbial degradation of organic material from both natural and anthropogenic accumulations. Secondary production results from the anaerobic microbial alteration of thermogenic crude oil (Jones et al., 2008; Milkov, 2011). Secondary biogenic gas is predominantly methane (Milkov, 2011), but also commonly contains ethane and heavier hydrocarbon compounds (e.g. Huang, 2015; Osadetz et al., 1994). It is this type of process that produced the heavy oil and bitumen that are abundant in Alberta, the largest example being the Athabasca oil sands (Huang, 2015; Ibatullin, 2009).

In the Western Canada Sedimentary Basin (WCSB), methane is a ubiquitous component of groundwater. Methane is also produced in near-surface environments, such as wetlands (e.g. Conrad, 1996), and in landfills (e.g. Themelis and Ulloa, 2007). Methane in the shallow subsurface can migrate directly to the atmosphere if its migration is not constrained by a caprock. Other migration pathways include natural fractures and leaky wells, both petroleum and groundwater types. There is significant evidence for much natural vertical migration of natural gas, on geological time scales, into the atmosphere from the WCSB (e.g. Huang, 2015; Humez et al., 2016a, b, c; Mayer et al., 2015). Other migration pathways, both lateral and vertical, occur within the subsurface, giving rise to petroleum accumulations and their biodegraded residues (Creaney et al., 1994).

On the surface of the earth, methane is produced from natural sources and processes, such as wildlife, termites, wildfires, and ocean dynamics (Etiope et al., 2008), and anthropogenic sources and processes, such as animal husbandry, petroleum production and refining, transport, and other industrial processes.

Wellbore leakage from hydrocarbon wells has been implicated in the contamination of groundwater in a small percentage of cases in Canada (e.g. Szatkowski et al., 2002; Tilley and Muehlenbachs, 2012). Considering the abovementioned variety of methane sources (thermogenic, primary and secondary biogenic), and the complicated pattern of migration pathways, it can be difficult to identify the source and pathway of contamination. While compositional characteristics of a gas may indicate the potential for contamination from leaky hydrocarbon wells, it would be desirable to conclusively demonstrate contamination using chemical tracers and migration models, especially since it is possible that the pumping of water from some water wells may be the process that induces the flow of methane into the well water (Moore, 2012).

In Alberta, significant work characterizing the composition and isotopic characteristics of SCVF and GM gases has been performed (Rowe and Muehlenbachs, 1999; Muehlenbachs, 2010). However, most of the details are not readily publicly available. SCVF and GM gas can have a variety or mixture of origins. About three quarters of

SCVF gas enters the well annulus from the geological successions above the production zone. The remaining quarter of SCVF gases originates from the producing zone. This ratio of source interval occurrence is similar for both vertical and horizontal wells (Muehlenbachs, 2012). Although there are fewer data from GM sites (Rowe and Muehlenbachs, 1999; Bachu, 2017), these too appear to originate predominantly from the geological successions above the producing zone.

However, the attribution of source intervals for gas samples collected from soil and groundwater samples (i.e. not collected directly from a hydrocarbon well or immediately adjacent to it) can be difficult, especially when they do not originate from the producing interval, as generally is the case (Muehlenbachs, 2012). Tilley and Muehlenbachs (2012, their Figure 2) illustrated that there is a considerable range of gas composition and isotopes in uncontaminated groundwaters. These challenges and uncertainties regarding migration pathways are discussed in more detail in the next section.

3.2 Current Practices, Regulations and State of Knowledge

3.2.1 Testing requirements

Throughout Canada, wells must be tested or monitored for SCVF or GM after they are drilled. New Brunswick and British Columbia require annual monitoring of all wells with SCVF and GM.

The Alberta Energy Regulator (AER) regulates the petroleum industry, including wellbore construction, testing, remediation and abandonment in Alberta. It requires new wells to be tested for SCVF within 90 days of well construction and prior to abandonment (AER, 2003). Gas migration testing is required in areas where GM is common or where the impacts on vegetation, groundwater or safety are obvious. Subsequent testing, monitoring and potentially remediation requirements depend on the results of the initial test. A surface casing vent test (SCVT) consists of a stringent bubble test. If the bubble test is positive, then flow rate and pressure are measured, generally with a positive displacement meter and digital pressure recorder. Emissions are reported in cubic metres per day or fractions thereof and are extrapolated to provide daily rates and annual emission volumes. Monitoring for GM and estimating emission rates is more difficult than SCVF because the flow is dispersed in the soil. Soil gas probes or other similar instruments are used to detect the presence of natural gas. The results are reported in parts per million or as a percentage of the lower explosive limit of methane within a sample.

Surface casing vent flows are classified as serious, considered non-serious, or non-serious. There are multiple criteria that may classify a leak as serious, including vent flow rate greater than 300 m³/day; the presence of any of crude oil, saline water or H₂S in the vent flow; where the stabilized build-up pressure is over 9.8 kPa/m times the surface casing setting depth; or if the SCVF is caused by a casing or wellhead failure. Wells that are not cemented over the groundwater protection zone may be “considered non-serious” if there are no water wells within one kilometre at depths below the surface casing; otherwise they are serious. Serious wells must be immediately

remediated to at least a non-serious condition. Non-serious wells must be monitored annually for five years or until the leak ceases. Non-serious wells that become serious must be immediately reported and remediated. Non-serious wells persisting past the five-year monitoring period must be remediated at the time of abandonment. Leaky wells and rates are systematically reported to the AER. Wells with GM are considered serious if the flow creates a safety hazard at the site.

3.2.2 Number of leaky wells and emissions

Alberta began monitoring for SCVF and GM as early as 1910 (Watson and Bachu, 2007). Since that time, around 25,000 wells have reported either SCVF or GM at some point in their history. This represents about 5% of the almost 440,000 wells drilled in Alberta. Among leaking wells, 89% reported an SCVF (5.8% of all wells); 10% reported GM (0.66% of all wells), and 1% reported both (0.6% of all wells). By well type, the most prone to leakage are inactive wells: 10.3% of all inactive wells have reported leakage. Abandoned wells are next at 7.0% (Boyer, 2016). As of April 2018, there were around 72,400 inactive wells and 184,400 abandoned wells in Alberta (AER, 2018). In 2016, 10,326 wells were leaking (**Figure 3.1**). Non-serious wells composed 96.7% (9,989) of these (AER, 2016a).

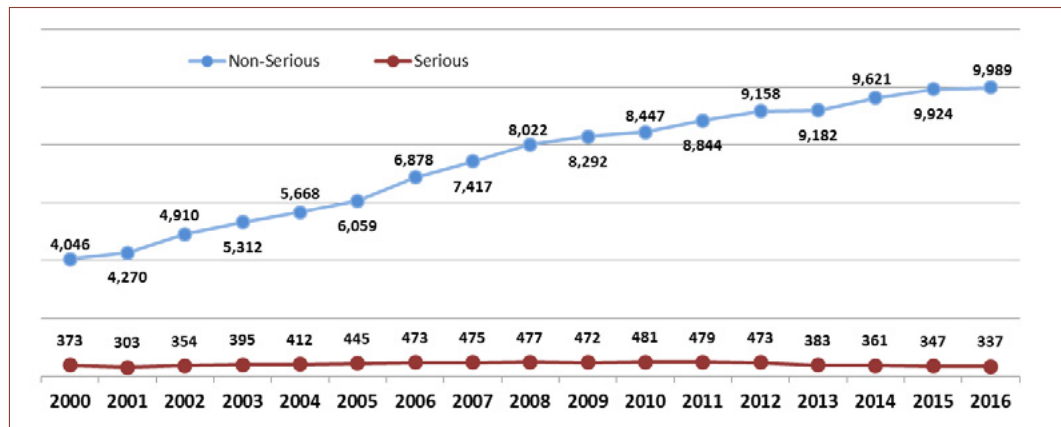


Figure 3.1 Natural gas SCVF/GM well counts as of June 2, 2016 (from AER, 2016a).

Figure 3.2 shows AER data for annual natural gas emissions for serious and non-serious wells from 2000 to 2016 (extrapolated from data up to June 2, 2016). **Figure 3.3** and **Figure 3.4** show, respectively, average daily natural gas emission rates for serious and non-serious wells, considering both SCVF and GM. Surface casing vent flow and GM data prior to 2000 is discussed by Watson and Bachu (2007).

The composition of gas from both SCVF and GM is not reported publicly, but based on unpublished sources (Muehlenbachs, 2010), the AER estimates that SCVF is 95% to 99% methane. Among non-serious wells, 31% report a gas rate that is too small to measure, and thus a default value of 1 m³/day is used. These uncertainties and limitations introduce some minor uncertainty into calculating annual and daily methane emission rates, which are discussed further in the Knowledge Gaps section. However, given that instances of GM are much less common than SCVF, it is considered reasonable to equate

“gas emissions” with “methane emissions.” While the 2016 average daily emission rate for non-serious wells is $\sim 13 \text{ m}^3/\text{day}$, the median rate is most likely less than this, as can be seen from the distribution of leakage rates for non-serious wells in Alberta between 2008 to 2013 as presented in Dusseault et al. (2014; their Figure 2.4) and for Alberta and B.C. in Nowamooz et al. (2015; their Figure 7). As reported in Dusseault et al. (2014), the average SCVF rate in B.C. is $9.6 \text{ m}^3/\text{day}$, while the median rate was estimated by the BC Oil and Gas Commission to be just $0.5 \text{ m}^3/\text{day}$. For comparison: a cow emits between $0.25 - 0.50 \text{ m}^3/\text{day}$ of methane (Johnson and Johnson, 1995); a typical oil-field pneumatic device operating under field conditions near Fort. St. John in northeastern B.C. emits $\sim 0.2 \text{ m}^3/\text{hr}$ of fuel gas (The Prasino Group, 2013), which, assuming this is only methane, equates to $4.8 \text{ m}^3/\text{day}$.

Beginning in the mid-1980s, concerted regulatory and industry efforts began to reduce the rate of well integrity issues (Watson and Bachu, 2009). As can be seen in **Figure 3.2**, total wellbore leakage emissions have been declining since 2008 and were $84.4 \times 10^6 \text{ m}^3$ of methane ($\sim 1.56 \text{ MtCO}_2\text{e}$) in 2016—which represents a reduction of 19% from the 2008 peak. This is attributable to a reduction in emissions from serious wells: **Figure 3.1** and **Figure 3.3** show, respectively, that both the number and average daily emission rate for serious wells have been declining since 2008.

For non-serious wells, their total annual emissions have increased slightly year over year (**Figure 3.2**). This is in spite of a reduction in their average daily gas emission rate (**Figure 3.4**). Thus, the increase in total annual emissions is accounted for by the annually increasing number of wells and fewer abandonments (**Figure 3.1**). The decline in average daily emission rate is partly attributable to improved well construction practices, particularly cementing casing to surface (Boyer, 2016).

Environment and Climate Change Canada (ECCC) uses an estimation method to calculate SCVF and GM emissions (ECCC, 2017c). For 2015, it estimated Canada-wide wellbore leakage emissions to be $7.2 \text{ MtCO}_2\text{e}$, and $5.0 \text{ MtCO}_2\text{e}$ for Alberta¹¹ (A. Osman, personal communication, July 24, 2018)¹². There is obviously a significant difference between Alberta’s well-based value of $1.56 \text{ MtCO}_2\text{e}$ and ECCC’s estimate of $5.0 \text{ MtCO}_2\text{e}$. ECCC reports both that there is a level of uncertainty in its method and that it is working on a new methodology that incorporates new data supplied by the AER (ECCC, 2017b). The discrepancy is discussed more in the Impacts and Magnitude report.

¹¹ 2016 results from ECCC’s National Inventory Report were not available at the time of writing, but wellbore leakage emissions were provided by ECCC (A. Osman, personal communication, July 24, 2018) and are similar: Alberta’s were $4.8 \text{ MtCO}_2\text{e}$ and Canada’s as a whole were $7.1 \text{ MtCO}_2\text{e}$.

¹² GHG emissions are reported to the Intergovernmental Panel on Climate Change (IPCC) according to a *Common Reporting Format*. Surface casing vent flow and gas migration from both crude oil (of all types) and natural gas wells are reported in the *Energy* category > *Fugitive Emissions from Fuels* sub-category > *Oil and Natural Gas* > *Natural Gas* > *Other – Accidents and Equipment Failures*. The CRF code is 1.B.2.b.6.1. (see Table A3-13 in in ECCC’s 2017 National Inventory Report 1990-2015, Part 2). However, while ECCC calculates emissions specifically for SCVF and GM, they are not reported individually in Canada’s National Inventory Reports. Instead, they are combined with other fugitive emission sources within the *Natural Gas* category (i.e. 1.B.2.b), such as natural gas production, processing, transmission, storage and distribution (i.e. CRF codes 1.B.2.b.2 through 1.B.2.b.5; see Table A3-13). Table 3-9 in the 2017 National Inventory Report, Part 1, lists these combined emissions under 1.B.2.b. Natural Gas.

For comparison, 7.2 MtCO₂e represents 4.3% of total upstream oil and gas sector GHG emissions of 167 MtCO₂e (ECCC, 2017c). Wellbore leakage emissions represent 13% of all fugitive emissions from the oil and natural gas sector, including upstream, downstream and oil sands/bitumen (ECCC, 2017c).

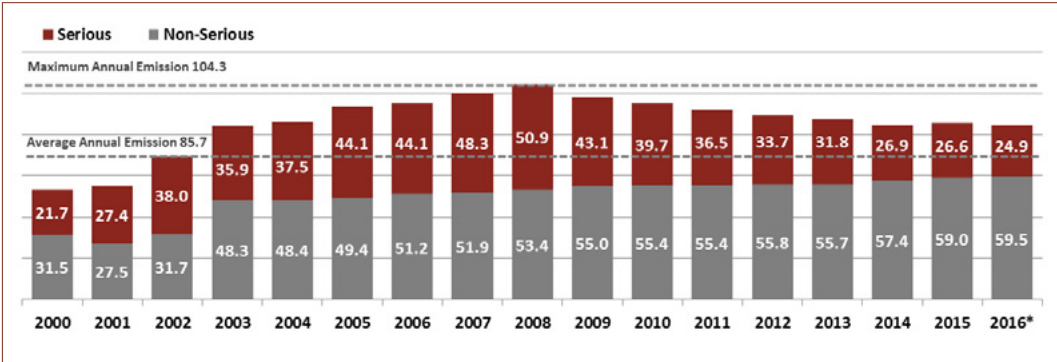


Figure 3.2 Annual natural gas emissions for SCVF/GM (10⁶ m³) as of June 2, 2016 with 2016 emissions extrapolated from the currently reported daily emission rate (from AER, 2016a).

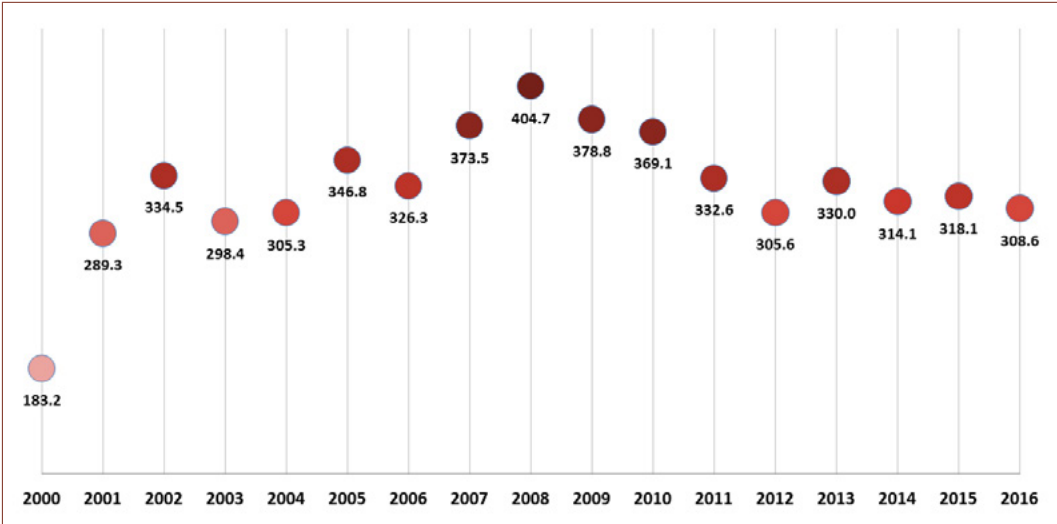


Figure 3.3 Average daily natural gas emission rate for serious SCVF/GM (m³/day) as of June 2, 2016 (from AER, 2016a).

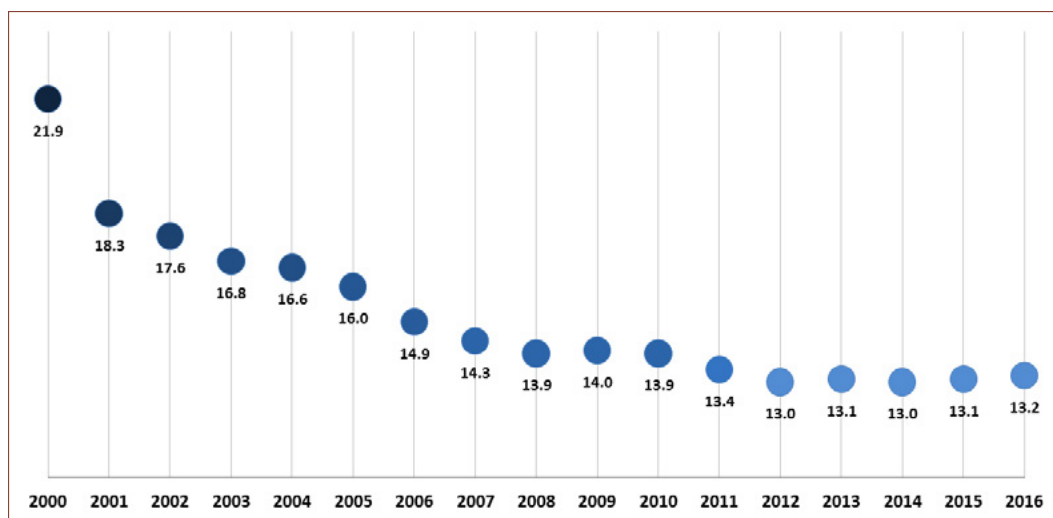


Figure 3.4 Average daily gas emission rate for non-serious SCVF (m³/day) as of June 2, 2016 (from AER, 2016a).

3.2.3 Impacts

The impacts of methane are agnostic of the source—natural or anthropogenic. This section discusses the impacts of methane on the environment and human health, with specific reference to impacts from wellbore leakage where possible.

Climate: Methane is a potent GHG with a warming potential 28 times that of CO₂ when considered over a 100-year period (Intergovernmental Panel on Climate Change, 2013). Wellbore leakage, particularly SCVF, contributes to anthropogenic emissions of methane, and as described in Chapter 1, both the federal and provincial government(s) have committed to reducing methane emissions from the petroleum sector. Their contribution relative to other sources of methane is discussed in the proceeding section on recommendations.

Air quality and safety: There is no direct link to human or animal health for non-safety-related exposure to methane itself (Jackson et al., 2011). The reaction of methane with NO_x species, primarily in urban settings, contributes to the concentration of tropospheric ozone, which is a health hazard (West et al., 2006). However, in urban areas, natural gas leakage tends to be related to distribution networks (Hamper, 2006; Jackson et al., 2014). Methane is a flammable and potentially explosive gas (Harder et al., 1965). However, the risks of this from wellbore leakage are considered remote because existing regulations “set back” petroleum facilities from inhabited structures.

Potable groundwater quality: The Council of Canadian Academies 2014 study on shale gas extraction identified wellbore leakage as a potential concern for impacting groundwater quality and recommended that it be studied. Methane itself in groundwater is not a hazard to human health. There is no Canadian or World Health Organization standard for methane in drinking water (Health Canada, 2017; World Health Organization, 2011), and methane contamination of groundwater is not a priority topic for the International Association of Medical Geologists (Bunnell et al., 2007; Centeno et al., 2016). However, the microbial oxidation of methane produces CO₂, which can change

groundwater chemistry and result in the release of metals and other substances that alter groundwater quality and potability (e.g. Kelly et al., 1985). These effects can be profound and extensive over large areas, as observed in association with a spectacular gas blow-out accident in an uncased hydrocarbon well in the United States (Kelly et al., 1985). However, it must be emphasized that well construction practices in Canada would make an accident of this magnitude extremely unlikely in Canada.

As described in the Background section, methane is a ubiquitous substance in many potable groundwater aquifers and soils, especially so in sedimentary basins with hydrocarbon and coal deposits, such as the WCSB. Its production and migration to the shallow subsurface may be natural and/or anthropogenic. Implicit acknowledgement of the widespread presence of methane in potable groundwater is indicated by Agriculture Alberta, which provided a diagram for a methane separator for groundwater wells (Alberta Agriculture and Forestry, 2017).

As described by Tilley and Meuhlenbachs (2012) and Meuhlenbachs (2012), there may be a considerable range of gas composition and isotopic signatures in potable water gas samples that may result from multiple sources and processes, even prior to oil and gas development, and this makes attribution of the source of such gases difficult to determine. In light of these points and for the purposes of this technology roadmap, we consider contamination of a groundwater protection zone to be the anthropogenically facilitated transport of a substance into a groundwater aquifer resulting from wellbore leakage. Methane is the substance of most concern, because it migrates easiest and is by far the most common component of SCVF and GM leakage.

In reality, any case of GM is essentially contamination of the groundwater protection zone. However, GM effects are commonly localized in the immediate vicinity of the well and often indicated by limited crop or vegetation stress (Godwin et al., 1990; Van Stempvoort et al., 2005; Vidic et al., 2013). However, only a few cases of GM document the impairment of drinking water protection zone as discussed below.

In Alberta and Saskatchewan, the limited studies on alleged groundwater contamination resulting from wellbore leakage include Godwin et al. (1990), Szatkowski et al. (2002), Van Stempvoort et al. (2005), and Tilley and Meuhlenbachs (2012). In some of these studies, the presence of thermogenic gases in the groundwater protection zone was attributed to wellbore leakage. It is likely that wellbore leakage was the source of all or part of the thermogenic gas detected in these studies; however, these studies did not examine or preclude the possibility that part of the contamination may be associated with the production of the water wells themselves. Pumping down the column of water in a water well reduces the hydrostatic pressure, which may enable methane to enter the well from a local source such as one of the Cretaceous coal zones common in the WCSB. Additional tools such as geochemical tracer studies, like those employed by Darrah et al. (2014) and physical migration models (e.g. Praagman and Rambags, 2008), were not used in any of these studies. In the future, it would be useful to perform more comprehensive studies of potential contamination cases.

Heavier hydrocarbons like ethane are attributed currently, and commonly, to thermogenic petroleum systems only (e.g. Brandt et al., 2014), and used as a tool to support claims of wellbore and petroleum facility sources of methane emissions and leakage. However, heavier hydrocarbon compounds occur commonly in “biogenic” gases elsewhere (Zhang and Shuai, 2015), particularly secondary biogenic gases. The possibility that these heavier hydrocarbons might have biogenic sources, or that they might occur ubiquitously in secondary biogenic gases as a by-product of the biodegradation of crude oils should also be considered (Huang, 2015; Osadetz et al., 2018).

In other jurisdictions, GM facilitated by shallow fractures has been observed and commented upon. However, the frequency of fractures increases towards the bedrock surface and, except for the previously noted cases of contamination, GM issues in the WCSB appear to have local impacts immediately adjacent to the wellbore.

Considering that in Alberta only 0.66% of wells developed GM issues, the question is: has wellbore leakage resulted in pervasive contamination of the groundwater protection zone? It is interesting to note that in Alberta, water well owners expressed high levels of general concern about the potential for methane in water wells, but rated methane as their most infrequent water quality issue with their own domestic wells (Summers, 2010).

Considering the relatively small number of documented cases of aquifer contamination and the substantial but still infrequent number of cases of GM into the GW protection zone, the risk of groundwater contamination from GM is still considered small given the number of combined cases of groundwater protection zone contamination and GM relative to the nearly 530,000 hydrocarbon wells drilled in Western Canada.

Vegetation: Vegetation can exhibit impacts as a result of methane migration into the groundwater protection and vadose zones of soil. In the vadose zone, plant health may be negatively impacted by methane at high concentrations, as can be seen by zones of dead or damaged vegetation surrounding wells with GM and also at natural seeps (**Figure 3.5**). The effects of anthropogenic and natural methane seepage are indistinguishable (Noomen et al. 2012). The impacts are rarely due to methane asphyxia, but more commonly due to CO₂-induced stress or asphyxia resulting from the microbial oxidation of methane (Hoeks, 1972; Davis, 1977; Drew, 1991). There have been several attempts to determine correlations between GM flux and the plant health impacts (Smith et al., 2005; Steven et al., 2006). However, no quantitative recommendations related to GM rate were developed due to the conclusion that GM impacts are complicated by many independent factors including, but not limited to, soil composition and characteristics, meteorological conditions, the microbial flora, and the plant species (Smith et al., 2005; Steven et al., 2006). Vegetation may also be impacted as a result of changes to groundwater quality arising from reactions occurring in an aquifer contaminated by methane, as described previously. These are reflected by crop or vegetation impacts near leaking wells, which sometimes result in plant mortality (Godwin et al., 1990; Van Stempvoort et al., 2005; and Vidic et al., 2013).



Figure 3.5 Typical pattern of vegetation impacts at the site of a naturally occurring gas seepage from Noomen et al. (2012, their Figure 4). In the centre of the seep, vegetation is either absent or attenuated. This is surrounded by a halo of “green vegetation” that gives way to “background” vegetation. The affected area has a radius of about 30 m; a person is shown scale on the left.

3.3 Knowledge Gaps and Recommendations

3.3.1 How many wells are actually leaking and how much?

There are a number of reasons that the AER’s database may either overestimate or underestimate the number of leaking wells and their emissions. During remediation of serious wells, about half report “die out” as the final repair action, but owners don’t immediately update the reduced flow rate to the AER until the well is deemed non-serious (some of these cases are likely due to wellhead issues and not downhole leakage). Some, and possibly many, non-serious wells die out during or subsequent to the five-year monitoring period, but operators don’t update the database for cost or administrative reasons, and the well is thus assumed by the regulator to emit at the previously reported rate. Some industrial sources reported that as many as 20% of their older non-serious wells ceased leaking without any remediation. In contrast, wells that tested with no leakage at rig release, or which were drilled prior to the testing requirement, may be leaking now, as evidenced by the fact that such leaks are discovered at the time of abandonment. Among non-serious wells, 31% report a gas rate that is too small to measure, which means that the default value of 1 m³/day is used even though flow rates as low as ~0.1 m³/day can be obtained (AER, 2016a).

Additionally, some SCVF rates are observed to be intermittent, variable, and sometimes reducing or disappearing over time (Watson, 2007); although this might also mean that emissions at a well are under-estimated. Thus, SCVF is sometimes not observable within the testing period (Alberta Innovates—Technology Futures, 2015). Watson (2007) found that some wells develop them later in life. Dusseault and Jackson (2014) postulate that they may develop in previously competent cement because of stresses imposed during wellbore integrity tests. Gas migration incidents occur much less frequently than SCVF;

however, quantifying leakage from GM is much more difficult. Thus, there appears to be sufficient motivation to re-examine the methane emissions database.

Recommendations to address knowledge gap: In order to better constrain the number of hydrocarbon wells that have leakage, and the magnitude of their emissions, the following recommendations are proposed:

Conduct a census of non-serious wells: This type of census isn't required for jurisdictions like British Columbia and New Brunswick, which require annual monitoring of all wells. However, for Alberta and similar jurisdictions, it would resolve many of the knowledge gaps noted above, and potentially reduce (or increase) both the number of leaky wells and emissions that are on the book. It could also help inform a selective remediation program that targets the currently largest leaking inactive wells that are unlikely to ever be returned to production, as well as inform other more cost-effective methane reduction options. Lastly, this type of data is required to better understand what made a well leak in the first place (including whether the leak is the result of casing failure, which is easier and less expensive to fix), and thus develop tools and regulations to address the underlying issue.

Determine temporal variations in well emissions: It is known that emissions from natural seeps fluctuate in response to environmental conditions. These same conditions may impact emissions from both SCVF and GM. Investigating SCVF and GM over a significant duration and under the various operating conditions a well may be exposed to would improve the accuracy of emissions estimates and inform monitoring requirements. Including a component to use and compare various GM monitoring methods would also help inform emissions estimates and monitoring practices. It would also help determine what impact near-surface environmental properties, such as seasonal water table height and frost level, have on GM emissions, and could inform well construction practices.

Compare improved emissions data against "top-down" emissions data: Data from both of the above recommendations could be used to compare against "top-down surveys" (i.e. atmospheric total hydrocarbon content surveys conducted by planes and/or drones), which commonly detect methane concentrations that are greater than "bottom-up" surveys based on equipment and process inventories (e.g. Johnson et al., 2017). This would help determine the source of discrepancies and inform methane reduction strategies.

3.3.2 When is remediating non-serious wells prior to abandonment a cost-effective way for the petroleum sector to reduce methane-related GHG emissions to the atmosphere?

The AER and other regulators require that wells with either GM or serious SCVF rates be remediated immediately. Non-serious wells must be remediated at abandonment, but the regulator may require their repair prior to this. Operators may temporarily stop production from a well because it is currently uneconomic, placing it on inactive status. Inactive wells are the most prone to leakage (AER, 2016a). While some wells may be brought back on line, the majority are likely to never be economic again (Muehlenbachs, 2017). The cost to abandon a well is a major reason why many well owners indefinitely

delay abandoning inactive wells (Muehlenbachs, 2017), and remediation costs contribute to this practice.

An option to reduce methane emissions is an accelerated or required abandonment of inactive wells that are unlikely to ever be economic again *and* that are the largest emitters of their type. However, from a cost-benefit standpoint, one should evaluate the efficacy and cost benefit of an accelerated abandonment strategy considering that the average cost to fix a well (including any related production losses) is estimated to be \$150,000 (Dusseault et al., 2014). In the Lloydminster area, remediation costs for one corporation are \$600,000 per well (Dusseault et al., 2014). Additionally, the use of vented caps on abandoned wells is an implicit acknowledgement that leakage may occur in abandoned wells, including those that were remediated before abandonment. Thus, it might be more cost effective to simply tax the emissions from minor emission sources and employ those funds to more effectively reduce methane emissions from other sources. For example, both the International Energy Agency's (IEA) *World Energy Outlook 2017* report (IEA, 2017) and the Pembina Institute/Environmental Defense Fund study of Canada's upstream petroleum industry (Environmental Defense Fund and Pembina Institute, 2015) list a number of key methane-emitting sources and abatement technologies. Both these studies suggest that in North America, 20% to 45% of total oil- and gas-related methane emissions could be eliminated using technologies that have no overall net costs or even provide a financial return (IEA, 2017). While the elimination of methane emissions could result in increased gas sales and higher revenues, the perspective of most operating companies is that the total costs of the required equipment replacement and facilities down-time to achieve these emission reductions will entail real costs to operators. The IEA report does not include wellbore leakage methane emissions in this group and the EDF/Pembina Institute used a Texas well leak detection and repair model to infer wellbore integrity issues in its study.

It is worthwhile to consider the impacts, costs and benefits of methane emission reductions from the upstream oil and gas sector in comparison with methane emissions from other anthropogenic sources in order to determine the net benefit of making the reduction of upstream petroleum industry emissions a priority. Total methane emissions in Canada in 2015 amounted to 102 MtCO₂e and accounted for 14% of total GHG emissions (Environment and Climate Change Canada, 2017b). Forty-two percent (42.8 MtCO₂e) were from fugitive sources in oil and natural gas systems (Environment and Climate Change Canada, 2017b). Wellbore leakage emissions are predominantly composed of methane¹³, and thus the 7.2 MtCO₂e calculated by ECCC for wellbore leakage emissions can be considered to represent ~7% of Canada's total methane emissions in 2015. Methane emissions from agriculture in 2015 were 29 MtCO₂e (28% of total), and those from landfills were 22 MtCO₂e (22% of total) (Environment and Climate Change Canada, 2017b).

¹³ CO₂ is a common constituent of natural gas, and thus wellbore leakage. According to ECCC, Canada-wide emissions from wellbore leakage in 2015 were estimated to be 0.0562 Mt CO₂, and 0.2862 Mt methane, for a total of 7.2124 MtCO₂e. Methane, based on a global warming potential of 25, as used by ECCC, makes up 7.156 Mt, or 99% of this. Thus, it is reasonable to compare methane emissions from wellbore leakage to other sources of methane emissions.

In some cases, it may be more effective for the upstream oil and gas industry, or for that matter other anthropogenic emitters, to pay into a fund that would be spent obtaining the largest reduction of Canadian anthropogenic methane emissions as a function of cost.

Recommendation to address knowledge gap: In order to achieve significant and cost-effective GHG reductions related to methane emissions, we propose the following:

Form a methane reduction strategy working group: The group would be tasked with examining, *from a GHG emissions perspective*, the cost and benefits of remediating non-serious inactive wells prior to abandonment in order to develop, if suitable, a process by which a GHG-based decision on remediation can be made. Data from the proposed well census, temporal variability, and top-down vs. bottom-up studies would help inform this task.

The output of such an exercise could include a table of “cost per cubic metre of methane reduction (or CO₂ equivalent)” for the suite of methane reduction options available across the entire petroleum sector. Armed with this knowledge, it may be suitable to consider a levy on methane emissions, as opposed to strict prescriptive control standards and regulations, so that efforts and funds can be directed to those reduction efforts that are most cost effective.

It may also be suitable to consider the application of these funds to achieve more efficient methane emissions reductions in other industrial sectors where the cost-benefit may be greater. This is a reasonable approach considering that the GHG impacts of methane are agnostic of the source and best achieved as cost-effectively as possible.

3.3.3 In consideration of other natural and anthropogenic sources, is there an acceptable leakage rate into soil and groundwater protection zones for non-serious wells with GM?

The public has a right to expect, and regulations to require, that the quality of groundwater upon which they may rely is not impaired by wellbore leakage, and that the effects of leakage on vegetation are not unacceptable. However, given that there exist multiple sources of methane in the shallow subsurface and that methane may migrate to the shallow subsurface via natural pathways in addition to leaky wells, it is proposed that it is reasonable to consider the effects of GM in light of these observations to determine if an acceptable GM rate exists. The effects of methane on groundwater quality and vegetation, as described previously, are highly dependent on the methane concentration, vegetation type and aquifer properties. Despite the number of GM instances in Alberta, there are few alleged GW contamination cases. The small number of contamination cases reflects the effective action of GM remediation efforts. It may be that the rate of leakage for the majority of wells is such that the effects are negligible or indistinguishable from those occurring due to other sources of methane, and this may speak to the capacity of aquifers to tolerate or “process” certain amounts of methane.

Recommendations to address knowledge gap: In order to determine if there is an acceptable GM leakage rate, we propose a field-based research program that would answer the following questions:

- ▶ What is the contribution of methane from wellbore leakage into a groundwater protection zone (including the vadose zone above the groundwater) relative to other non-wellbore leakage-related sources of methane (e.g. primary and secondary biogenic methane, thermogenic methane that has migrated via natural processes)? Such studies will require the application of multiple methods of investigating GM and methane distribution in the subsurface, including the use of chemical tracers (e.g. Darrah et al., 2014) and physical migration models (e.g. Praagman and Rambags, 2008).
- ▶ What is the impact of methane on groundwater quality and biota in the study areas, and how is it related to aquifer properties (e.g. mineral, gas, water composition), soil properties (e.g. composition, microbial community), vegetation type, and other factors?
- ▶ The Alberta Agriculture website¹⁴ provides plans for water well natural gas separators. What are the circumstances and what is the magnitude of the methane emissions that result from the operation of potable groundwater wells; in other words, what are the contributions of water wells to atmospheric methane emissions?

Such a program must take into account the cumulative impacts of wellbore leakage and potential leakage resulting from potential future development. Armed with data resulting from such a research program, it is likely feasible to develop a risk-management strategy that accounts for site-specific properties to determine if acceptable, and perhaps higher than currently permitted, SCVF or GM rates exist that ensure the impacts from wellbore leakage are acceptable. The application of this process may result in the non-requirement to fix some wells with GM and SCVF which would currently have to be addressed. This would have a number of beneficial impacts: orphan well associations would be able to abandon more wells for less money, which would reduce their funding shortfall. It may also facilitate the abandonment of uneconomic inactive wells (i.e. those likely to never come back on line) as the cost to an owner to abandon them is reduced and more manageable. As noted by Lucija Muehlenbachs (2017), “The financial burden of abandoning a well officially is no doubt why Alberta producers delay doing so as long as possible.” Also, regulators might consider applying a levy or tax for the right to emit methane via GM and/or SCVF), and the funds from such a levy could be applied to reduce methane emissions elsewhere in a more cost-effective manner. Lastly, this type of knowledge would allow regulators to develop a ranking of leaky wells to remediate in order to fix those that are causing the largest detrimental impacts.

¹⁴ <https://open.alberta.ca/dataset/217842a8-0e36-4002-9331-06293f2c8ec5/resource/0523e4c4-d946-42ff-b848-6bfbbc0678a6/download/35386312006agri-factsmethanegaswellwater.pdf>.



Drilling and Completions

This section discusses the materials and processes used in well construction, summarizing the full TRM report entitled *Improving Well Construction Materials and Procedures to Reduce Wellbore Leakage*, which was a compilation of reports from Fire Creek Resources Ltd. (Dean Casorso and David Ewen) and Bisset Resources Consultants Ltd. (D.S. Belczewski)¹⁵. Well construction is critical because the details of how a well is constructed determine the ability of the well to maintain hydraulic isolation between geological strata. Improving well construction will reduce the need for expensive remediation in the future. The well construction process commences with the well design, followed by equipment and material procurement and mobilization, drilling and completion of the well, and finally job closing activities including SCVF/GM testing.

4.1 Current Practices and Regulations in Well Operation

The design of a well involves a multidisciplinary collaboration between drilling engineers, geologists and reservoir or production engineers with a focus on the well's objective and target formation location. Design parameters include hole size, directional planning if applicable, casing and connections, cement slurry design, drilling fluid, centralization, fluids pumping rates, and scratcher deployment. All of these design choices may impact zonal hydraulic isolation. Numerical modelling may play a role in the design process, but many of the input parameters are subject to problems of availability and/or uncertainty, which can be partially mitigated by using a sensitivity analysis. The main objectives during drilling are to ensure removal of cuttings, prevent exchange of drilling fluids with the formation, promote borehole stability, and allow a satisfactory rate of penetration.

After a particular stage is drilled (surface, intermediate or production) to the desired casing setting depth, the drilling mud is circulated to move fluids from bottom to surface to remove all drill cuttings prior to running casing. Long circulation times should be avoided to decrease the risks of borehole instability. It is recommended, particularly in deviated wells, to increase pumping rates to create turbulent flow, while taking care to avoid inducing a fracture. After circulation, casing strings are connected and run into the well. Before and during running of the casing, the centralization plan is typically revised, and connection make-up torque, fluid levels and trip-in speed are monitored. The threaded connections must be able to provide a pressure barrier between the internal and external fluids. Once the casing is landed at the desired depth, drilling fluid is pushed out the borehole, displaced by a spacer or scavenger fluid. **Figure 4.1** illustrates the cementing components.

¹⁵ The Bisset Resources Consultants Ltd. Report, entitled *Construction and Abandonment Design for Life Cycle Wellbore Integrity*, was prepared for the Petroleum Technology Resource Centre's (Regina, Saskatchewan) *CO₂ User Project*, and was graciously provided to NRCAN to assist with the *Technology Roadmap to Reduce Wellbore Leakage*.

Spacer fluids are used to flush out drilling fluid products in the wellbore that are incompatible with proper curing of cement. Spacers generally have low viscosity, which enhances turbulent flow. If the drilling fluid is required to be at high density for either well control or wellbore stability reasons, the spacer fluids may be weighted to avoid major changes in bottomhole pressure. Greater spacer volumes ahead of the cement slurry are generally beneficial for improving removal of mud and filter cake, which is gradually eroded by the flowing spacer fluid. However, increased exposure time to low viscosity and generally less inhibitive spacer fluid increases the likelihood of wellbore instability and collapse around the casing string. For areas where wellbore stability is an issue, reduced volumes of spacer fluid may be a better choice.

After circulating the spacer fluid, cement slurry is pumped into the well, displacing the fluid within the well, and replacing it with cement. With conventional cementing down casing (as opposed to inner string or reverse cementing), before pumping cement, a wiper plug (bottom plug) is installed in the casing. This plug travels in front of the cement, cleaning the inside of the casing, and preventing the cement from mixing with the fluid inside the casing. The cement slurry flows to the bottom of the wellbore through the casing, until the bottom plug reaches the float collar, just above the bottom of the hole. The pump pressure is increased until a diaphragm within the bottom plug ruptures, allowing the cement to flow through to the bottom of the hole, around the base of the casing and up the annulus of the well. After the appropriate volume of cement has been pumped (based on the estimated volume of the annulus, plus an excess), the second wiper plug (top plug) is pushed down the casing by a displacement fluid, and pumping continues until the top plug meets ('bumps') the bottom plug. The cement now fills the annulus, and is allowed to set, creating a seal to prevent fluid flow between the formations penetrated by the well. The cement also protects the casing from corrosion and increases mechanical stability.

A cement blend must be designed specifically for the casing string, depth, temperature, pressure and ultimate use of that portion of the borehole. The surface casing cement program is typically a very basic design. Generally, the surface casing cement has no special additives and no special spacers are used because the surface hole is drilled with gel chem mud systems and the geometry of the hole isn't an issue because surface intervals are typically vertical. However, the importance of avoiding gas migration through casing cement column and within the surface casing/surface hole annulus is important.

If a casing pressure test is required after the top cement plug bumps the bottom plug, it should be done before the cement has gained significant gel strength to reduce any disturbance of the bond between the casing and cement. Alternatively, the pressure test can be done after the cement has gained sufficient compressive strength. Section 25.9.3.2 of DACC's *Industry Recommended Practice #25: Primary Cementing* (DACC, 2017) notes that, usually, a minimum compressive strength of 500 psi (~3500 kPa) is required before drilling out the casing shoe. The CSA's *Z625-16 Well Design for the Petroleum and Natural Gas Industry Systems* is stronger: Section 6.3.3 states that "The casing shoe *shall not* be drilled out until the cement has reached sufficient compressive strength (3500 kPa) to allow safe drilling operations or following the elapsed time specified by the authority having jurisdiction. Regardless of the drill out time, the cement shall have a compressive strength of at least 3500 kPa after 48 hours at formation temperature." (CSA, 2016)

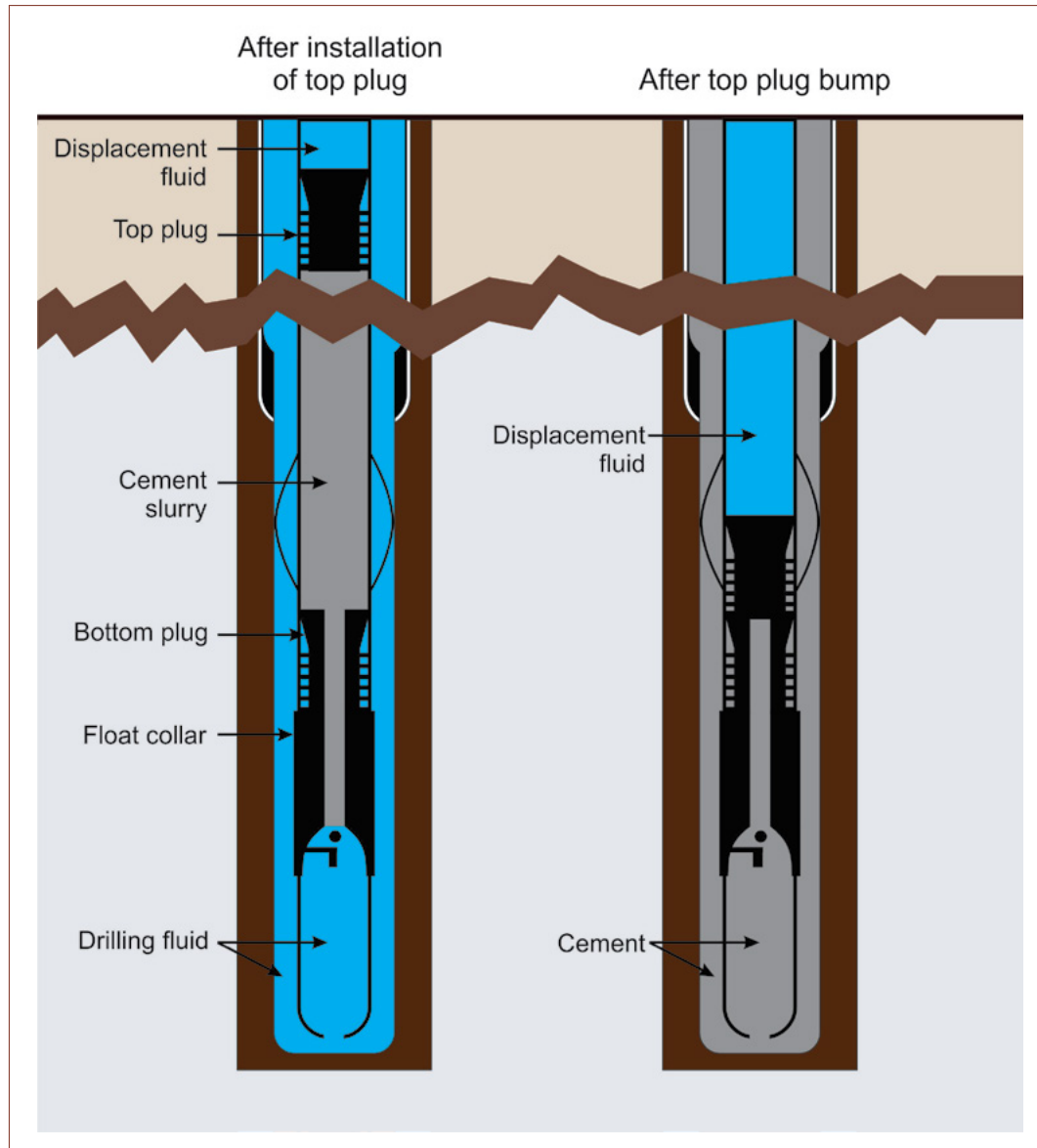


Figure 4.1 Schematic of cementing components.

4.2 Problems Encountered with Current Wellbore Construction Practices

Typical drilling problems include well control situations where formation fluids invade the borehole (kicks), loss of circulation where the drilling fluid invades a penetrated formation, and borehole instability. Borehole instability is the undesirable condition in the open hole which results in the open hole gauge size and shape and/or its structural integrity being compromised. Drilling problems may be severe enough that they lead to a complete loss of the well.

Connection failure, in conjunction with annular cement failure, can result in gas or liquid escaping from inside of the casing and manifesting as a surface casing vent flow or gas migration. The proper selection of casing connections, based on the mechanical load, pressure, temperature and chemistry, is critical to ensure casing integrity. For instance, the BC Oil and Gas Commission (2015) issued a reminder that high pressures associated with hydraulic fracturing down casing with American Petroleum Institute (API) Long Thread and Coupling connections could compromise the casing integrity and lead to SCVF. Vignes and Aadnoy (2010) showed that 2% of 406 Norwegian offshore wells had integrity failure due to casing connection or collapse (King, 2012). An additional concern is the proper application of thread compound to API connections. The thread compound is an integral part of the connection seal. It is applied while casing is run in the hole, often by a rig member with limited training, and with little oversight during the application. Testing of connections while running casing is seldom done.

Uncemented sections of the annulus are a major cause of SCVF, GM, and casing failure due to external corrosion (Dusseault, 2014; Watson, 2007; Carrol, 2016; Chafin, 1994; Hetrick, 2011). Unintended low cement top, when there are no cement returns at surface, may result from lost circulation, leak-off or an underestimated annular volume (Hetrick, 2011). Lost circulation can result during cementing due to excessive effective circulating densities, which cause the formation to fracture due to high pressures. In wells that do not have multi-arm caliper surveys conducted prior to cementing, the annular volume may be underestimated because the calculation generally uses the gauge borehole diameter and some rule of thumb excess. This practice can severely underestimate the volume when wells have significant borehole washout. In some cases, wells may be designed with low cement due to the inability of deeper zones to withstand the hydrostatic pressure of a full cement column, lack of regulatory requirements to cement into the next string of casing (or to surface), or economic considerations. Technologies to assist in full column cement placement are available. These include stage cementing or external casing devices, such as cement baskets, which may help to reduce cement fall back.

The placement of cement requires the displacement of residual drilling fluids in the wellbore. Based on experience and observations over many years, some extreme examples of cement channeling are believed to be a direct result of incompatible residual fluids in the annulus coming in contact with either the tail or especially the lead cement slurry (Agbasimalo, 2012).

When preparing cement slurry, cement bulk tanks feed the dry cement powder and mix water into the cement pumping unit. In such a system, holding the cement density steady in an on-the-fly or jet-cone mixer requires an experienced operator. Maintaining the correct density of the cement slurry at the tail end of the job can be very difficult due to low levels in the bulk tank, no ability to gauge tank levels, cement powder hang-up in the tank, and complications from humidity resulting in lower feed rates of the cement powder. The result is a poor-quality cement around the casing shoe, the location where cement integrity is most critical.

Installing BOPs or pressure testing can cause casing movement before adequate cement compressive strength has developed and may cause a microannulus to develop

(DACC, 2016). Formation leak-off pressure tests conducted to ensure the casing shoe has adequate strength may expand the casing and may create a microannulus when the casing is unloaded and the pressure drops (Boukheifa, 2005; Bois, 2011). Drilling ahead, perforating, or performing stimulation treatments such as hydraulic fracturing too soon after a well is cemented can also cause cement sheath failure. CSA Z625-16 recommends waiting on cement before drilling out until a minimum of 3500 kPa (500 psi) compressive strength has been developed (CSA, 2016). Establishing adequate compressive strength may be complicated in long cemented intervals where there is a large temperature differential between the top and bottom of the interval. Because the rates of hydration and curing are highly temperature dependent, compressive strength may be adequately developed at the bottom of the well where temperatures are higher but may be inadequate at shallower depths at lower temperatures (Witt, 2016).

A relatively common practice that may result in the formation of a microannulus is the use of high-density displacement fluid to displace the cement slurry. This occurs quite often in wells where high-density fluid is used for both the section of the well that is being cased and for drilling the section of the well that is below the casing currently being run, generally in deeper wells. This might be done because it may be operationally simpler to continue using the fluid when drilling out and avoid circulating out a different type of displacement fluid from the well. High-density displacement fluids increase the risk of creating or enlarging a microannulus because the casing balloons when exposed to a high differential between internal and external pressures. Thin-walled casing strings suffer more from this effect than do thick-walled casing strings. The cement sets with the casing expanded and when the pressure is reduced after the high-density fluid is replaced with a lighter fluid, the casing retracts pulling the casing away from the cement sheath and creating a microannulus.

Even where drilling problems are not an issue, connections do not fail and the entire annulus is cemented, wells may still leak. The reason is that cement placement in a deep borehole, particularly in the annular space outside the casing, is difficult. There are a large number of things that can go wrong, leading to poor sealing against gas movement. The potential problems that may affect the integrity of hydrocarbon well annuli (both during production and post-abandonment) are outlined in Dusseault et al. (2014), where wellbore integrity problems leading to gas migration were divided into short-term and longterm issues. According to them, short-term issues affecting the cement sheath include:

- Improper drilling mud and cement slurry design: Results in cement that is unable to provide an adequate seal, regardless of the care and quality control during cement placement.
- Inadequate mud removal: This causes poor bonding of cement to borehole walls, or mud contamination of the cement slurry, which can result in reduced pumpability, reduced compressive strength, prevention of slurry gelation, and creation of channels or voids as embedded mud dehydrates (Figure 4.2).
- Eccentric casing placement: This contributes to poor mud removal and is a particular problem for deviated (and horizontal) wells.

- Invasion of gases or liquids during setting: This may occur if cement does not maintain sufficient hydrostatic pressure until the slurry has developed sufficient gelation or strength to resist gas invasion. This is a function of slurry design and wellbore conditions (Crook and Heatherman, 1998) (Figure 4.3).

And, long-term issues affecting the cement sheath include:

- Operating stresses, including cyclic pressure and/or thermal stresses: These cause expansion or contraction of the casing and cement sheath, and stress relaxation (or creep) at elevated temperature and stress, which may result in debonding and development of cracks or a microannulus. Casing expansion has also been shown to cause axial and radial tensile, shear or compressive fractures in the cement sheath and permanent (plastic) deformation. These issues are acute in high-temperature enhanced oil recovery or hydraulic fracturing wells (Figure 4.4).
- Cement shrinkage: This may be due to the expulsion of water into permeable formations, autogenous shrinkage due to the reduced volume of cured cement, or perhaps osmotic dewatering. This can greatly reduce the radial confining stress, resulting in the development of a microannulus. This issue was studied quantitatively in a recent modelling study by Oyarhossein and Dusseault (2015), which confirmed the validity of this conceptual model of microannulus development.
- Corrosion and cement degradation: Steel casing corrosion diminishes the mechanical integrity of the casing and may lead to leakage problems. Degradation of the cement sheath may also enhance pathways caused by corrosion, drilling damage, cement shrinkage, or others.

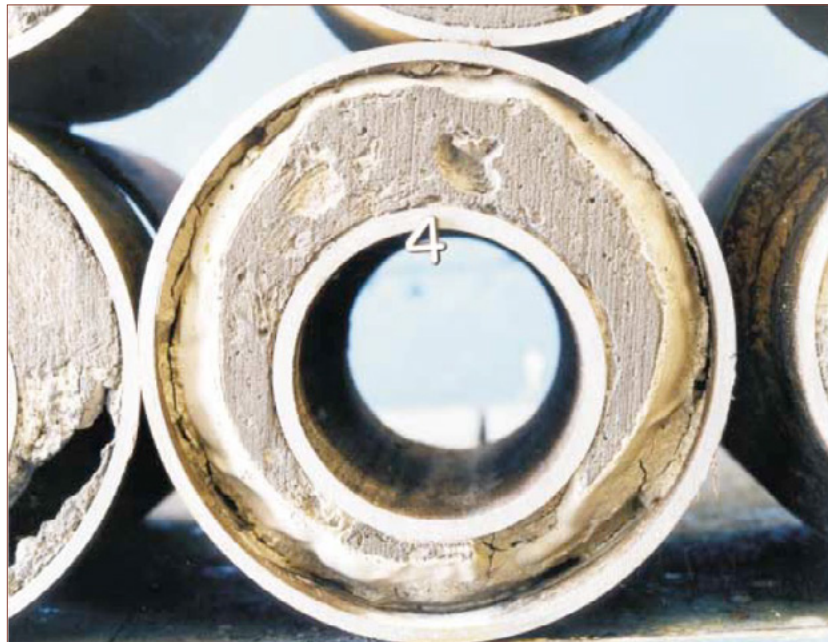


Figure 4.2 Incomplete displacement of drilling mud and resulting cement and drilling fluid channels. Over time, the gels in the drilling fluid well shrink, forming a gas flow path in the annulus (Watson et al., 2002).



Figure 4.3 Gas channels and gas pockets formed in set cement as a result of gas migration (Watson et al., 2002).

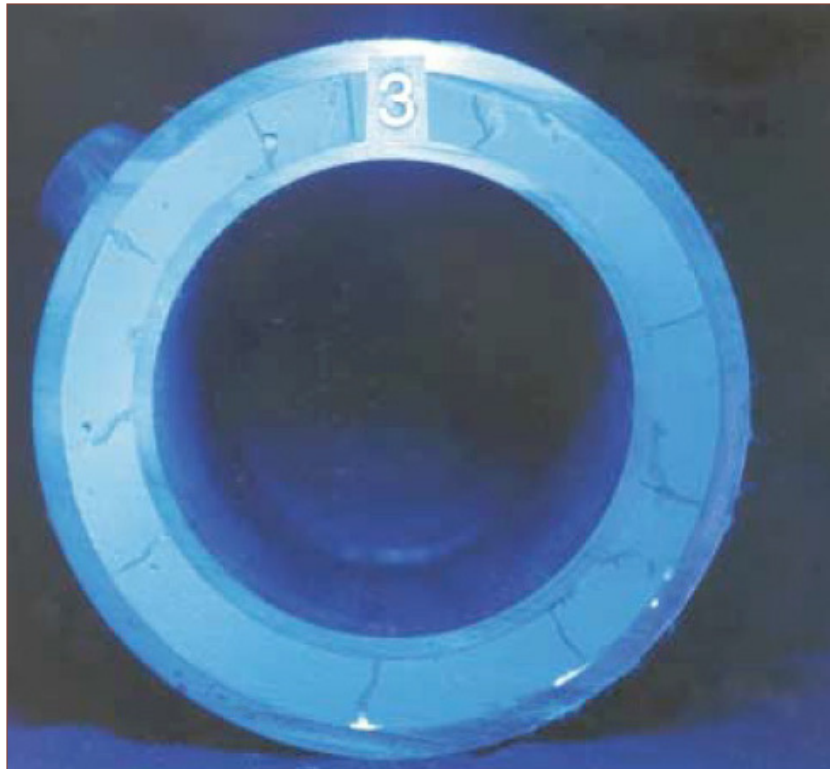


Figure 4.4 Cement sheath failure and resulting cracks developed from pressure cycling (Watson et al., 2002).

4.3 Improving Operational Practices with Existing Technology

The following recommendations can be made to improve well construction practices, with a goal of reducing rates of surface casing vent flow and gas migration:

- ▶ **Run open-hole log suite including x-y caliper log** in all wells in order to assess hole geometry and conditions in the wellbore. X-Y caliper logs will indicate areas of washout or narrowing, important when planning where additional centralization may be required. Knowledge of problem areas may also help determine where to remediate if leakage does occur. The caliper log allows a better estimate of the required cement volume, reducing the risk of a low cement top.
- ▶ Dusseault et al. (2014) commented that **better centralization** may be the most cost-effective method to reduce wellbore leakage in new wells. Poor centralization seems to contribute to gas leakage in many wells, especially deviated and horizontal wells. According to Dusseault et al. (2014), Shell Canada has been using one centralizer per casing joint in vertical sections of its wells in the Montney and Duvernay plays in Alberta and British Columbia, improving the quality of primary completions. Borehole information along with deviation surveys should be used to simulate the most effective centralization program. Care should be taken to ensure that centralizers are properly installed and that field operations follow all protocols.
- ▶ **Pipe rotation** is the most effective physical method to remove drilling mud, particularly in high-angle sections of the hole where the pipe and cuttings lie on the low side of the hole. Without rotation, the active flow area is over the top of the pipe and cuttings bed. It is nearly impossible to remove this cuttings bed without mechanical agitation. Rotation causes a “viscous coupling” effect that pulls the cuttings up into the active flow area and enables their removal (Mims and Krep, 2003). It is also effective at removing mud in well sections where the casing is close to the wall of the wellbore (Zulqarnain, 2012). Studies within the industry have shown that rotation is more effective than reciprocation under most conditions (Nelson and Guillot, 2006). The most significant barrier to casing rotation is the fear of over-torqueing and fatigue development of casing connections while rotating (Xie et al., 2011). Advances in controlled drilling, computer modelling software, and the ability of drilling rigs to limit rotary torque make pipe rotation increasingly feasible. In some deviated wells pipe rotation may not be advisable, but in these situations improved centralization, fluid flushes, spacers and pump rates must be designed to compensate for the lack of pipe movement.
- ▶ **Ensure casing design accurately identifies the loads** that the well will be exposed to throughout the life cycle and specify connections that will withstand these loads throughout the life of the well. Other possible improvements could include testing of casing connections while running in, improved training of rig crews for running of API and non-API connections, and increased use of premium connections in a broader category of wells.

- ▶ **Remove mill varnish from casing prior to running.** Sandblasting roughens the surface of the casing and improves the chance of direct contact of cement to the casing wall surface, which can significantly improve the cement bond with the casing wall (Carter and Evans, 1964). Transporting and sandblasting casing may be inconvenient but is less so if done in larger batches.
- ▶ **Utilize well integrity management systems** to allow designers to assess the risks associated with the well construction and future operations (International Standards Organization [ISO], 2017; DACC, 2012). The AER has a requirement for integrity management systems for pipeline construction and operations but there is no similar requirement for wells.
- ▶ **Implement longer wait on cement times.** Loading the cement prior to full-strength development can lead to the formation of a microannulus between the casing and cement sheath. Not all jurisdictions have regulations requiring wait on cement time or cement strength development prior to drilling out the previous casing shoe, before BOP removal, or before completion operations commence.
- ▶ **Limit the use of high-density displacement fluids** wherever possible. High-density displacement fluids increase the risk of creating or enlarging a microannulus because the casing balloons when exposed to a high differential between internal and external pressure. The cement sets with the casing expanded, and when the pressure is released, the casing retracts and a microannulus is created between the casing and cement.
- ▶ **Follow all best practices for cement design** and where possible, use cements that have more resilience in both compression and tension. Mandating cement properties other than compressive strength, such as tensile strength, time to development, maximum fluid loss, or minimum transition time, might also improve zonal isolation.
- ▶ **Cement full length** or, at a minimum, well into the previous casing string. It is best practice to cement at least 50 m past the previous casing shoe, and where possible to surface. There may be some advantages to limiting the cement height inside the previous casing to facilitate repairs on shallower casings. Whether this benefit outweighs the risk of corrosion in the uncemented casing is unknown.
- ▶ **Pump rates during cement placement should be as high as possible** to have flow in the turbulent to near turbulent regime, to assist in mud and cuttings removal. Very high displacement rates should be tempered by the potential risks associated with high pumping rates, such as hole wash-out, loss of circulation and/or creation of an annular pack-off with cuttings or sloughing shales. To improve cement flow characteristics, various blend additives such as turbulence inducers (friction reducers) can be added. While it may not be possible to achieve full turbulent flow by altering the rheology of cement slurries, reduced gel strengths and low shear rate rheology will induce eddies and other irregular flow patterns that aid in mud removal.
- ▶ **Alternative cement/sealant designs** (e.g. resins) in key caprock and aquitard layers, cement additives to increase elasticity/ductility, pre-flush/pre-treatment (e.g. with silicates) to improve cement placement and reduce leak-off.

- **Pumping additional cement volume** past any given point in the wellbore will increase the areal percentage of cement, while simultaneously reducing the areal percentage of residual filter cake and fluids such as mud, hydrated drilling fluid, spacer fluids and formation fluids. Increasing the cement volume remains one of the best methods for contributing to a good quality cement job.

The oil and gas industry has prepared and widely distributed many publications regarding best practices for addressing wellbore leakage. These best practices are based on years of scientific research and field implementation. A sample of these recommended practices and standards follows.

- **Drilling and Completions Committee (Enform) IRP 3:** In Situ Heavy Oil Operations – An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry, Volume 03 – 2012: Addresses casing design, cement design, cement placement, operational integrity and other special considerations for thermally produced wells.
- **Drilling and Completions Committee (Enform) 24:** Fracture Stimulation – An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry, Volume 24 – 2016: Addresses well integrity issues associated with high pressures in the casing. The recommendations for well integrity assessment could be used prior to loading the casing and cement sheath in the construction phase.
- **Drilling and Completions Committee (Enform) IRP 25:** Primary Cementing – An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry, Volume 25 – 2017: This IRP supports the findings of this review in terms of centralization and pipe movement and should be relied upon to achieve wellbore integrity.
- **Canadian Standards Association CSA Z625-16:** Well design for petroleum and natural gas industry systems: This standard provides an exceptional guide to well design for conventional and deviated wells, offering an excellent list of standards and best practices. The standard also discusses a design philosophy to ensure wellbore integrity.

4.4 Knowledge Gaps and Research Recommendations

Our literature review and interviews have identified several areas of new technology and research that could be pursued. These include:

- **Cement additives, elastomers, fibers:** Fibers and elastomers may help cement self-heal after it has been compromised. These added components react with migrating hydrocarbons or aqueous fluids to expand and seal off small leaks. Cavanagh et al. (2007) presented data showing closure of a 100micron microannulus within 6 hours, despite a differential pressure up to 5.3 MPa/m. Additives that increase the resilience of cement may also be beneficial in achieving longterm sealing after cyclic well loads—a promising candidate is microporous spongy carbon (Zhou, 2015).
- **Placement techniques:** Slow-rate cementing and vibration post placement have shown promise in reducing SCVF and GM in shallow wells. However, the techniques

have been employed while ensuring other best practices are in place (i.e. no independent control), warranting further investigation to better understand these success stories. Heating of displacement fluid or circulating warm fluid to increase wellbore temperatures and accelerate cement setting times may be beneficial in shallow wells with low temperatures. However, this technique could enhance microannulus formation due to thermal strains.

- ▶ **Pipe movement:** Pipe movement is identified as an important practice in establishing wellbore integrity but is often not used (especially rotation). Concerns regarding pipe fatigue, torque limits and inadequacy of available equipment lead field operators to make the decision not to move pipes. The use of API connections may also be a source of concern. Upfront fatigue/damage analysis supported by lab data and better communication between engineering and field personnel regarding the risks of pipe movement may allay some fear. More use of semi-premium and premium connections would enhance confidence in this practice.
- ▶ **Swellable casing attachments:** Swellable technology shows promise in the reduction of SCVF and GM. External casing packers (ECP) have been used in the industry for over 70 years (Webber, 1949). Traditional ECPs used cement, mud or another fluid to inflate an annulus-sealing element, but are not always deployable (Bonett, 1996). Swelling rubber bonded to the casing (swellable ECPs) can work in well conditions that limit the application of traditional ECPs. The elastomers swell when exposed to a particular fluid, sealing microannuli or open mud channels (Carrion, 2011). Swelling rubbers function autonomously, swelling multiple times if re-exposed to the activation fluid. More research is warranted to develop products designed to swell in specific instances, such as in contact with gases like methane, CO₂ and H₂S or specific water chemistries.
- ▶ **Simulation:** Simulation programs with user-friendly interfaces employing typical, easily acquired inputs should be developed for engineers to use in the design stage and for field personnel to quickly assess changes required in centralization plans, and to determine the forces exerted on the casing during reciprocation and rotation.
- ▶ **Centralizer design and installation:** A survey of the literature and interviews with operators suggests that the barriers to proper use of centralization include the lack of information to accurately simulate centralizer placement, reliance on rules of thumb, lack of training, lack of specifications for installation, and poor centralizer design. Based on the concerns raised by field staff, research on improved centralizer design and installation processes is recommended.
- ▶ **Risk-based well integrity management:** Development of risk-based well integrity management systems that would be implemented and enforced by regulators should be investigated (ISO, 2017).

The preceding list is helpful, but this review has identified some significant barriers to the use of new technologies and best practices. These barriers are generally operational or economical, under regulatory regimes that specify minimum standards that do not meet the integrity needs of specific wells.

Economically, the impact of the additional time needed to drill a well is significant. Generally, drillers are paid per metre drilled per time and encouraged to use low-cost well construction materials, and technologies and practices that may not consider long-term well integrity. The pressure to drill wells as inexpensively as possible results in the shortest wait-on-cement times, the most inexpensive cement additives to meet pumping criteria, limited logging, application for waivers wherever possible, and the infrequent use of premium casing connections.

Generally, there is little consequence to an operator that has constructed a well with poor integrity. Wells with 'nonserious' SCVF or GM are allowed to produce, and repair is put off into the future until abandonment. Regulations that include penalties for operating a well with compromised integrity could provide an incentive to follow known best practices.



5. Source Identification

This section is a summary of the TRM report entitled *Improving Wellbore Leakage Source Identification to Increase Remedial Intervention Success*, produced by Rose McPherson and Paul Pavlakos of Weatherford Canada, Calgary, Alberta. Accurate source identification is critical to achieving a successful remedial intervention. For instance, if a remedial attempt is placed too far above the source formation, build-up of pressure from greater depth can exceed the local confining stress and result in breakout/seepage to formations or degradation and eventual breakdown of the remedial seal. If the remedial seal is placed below the actual source zone, the intervention will have no remedial impact and can jeopardize casing integrity. Sources of migrating gas are commonly at intermediate depths between production zone and base of groundwater protection. Typical long-term gas flow rates produced by intermediate formations are on the order of 1.0 m³/day. Low flow rates make source identification difficult. In this section the current state of technologies is summarized, knowledge gaps are identified, and new avenues of research to improve source identification are proposed.

5.1 Current Practices and Regulations

Current industry practice is to assess source rock, cap rock, fluid movement and flow path of the leaking fluid, but with minimal to no data collection effort. Formation log information and drilling history can be used for potential source identification, as can information from offset wells. Information such as kicks, lost circulation and tight hole while drilling will provide information regarding where high permeability intervals exist in the wellbore. Investigation of cuttings, mud gases, mud conditioning prior to cementing, hole deviation and well cementing charts can also provide clues to identify the source interval.

The available methods used for active source identification can be divided into three categories: (1) acoustic energy measurements; (2) carbon isotope measurements; and, (3) formation evaluation measurements.

5.1.1 Acoustic energy

Turbulence in flowing fluid generates sound. A downhole noise logging tool can measure the acoustic profile of the wellbore to characterize flow in the annulus. In this method, a conventional hydrophone is suspended downhole in the wellbore fluid and acoustic measurements are taken at a series of locations, requiring several minutes at each level. This method was adapted for identifying behind-casing leaks in the 1970s, (Maslennikova et al., 2012). An increase in noise amplitude or frequency magnitude of the recorded signal may be interpreted as fluid movement due to a source zone (Maslennikova et al., 2012). Leaks behind the casing can have a distinct frequency structure that permits discrimination between two-phase and single-phase flow regimes, and an order of magnitude estimation of the leak rate. This interpretation is confounded by the fact that turbulent flow through a restriction or a change in flow path can also create sound downhole.

Hydrophone technology from the 1970s has significant limitations in low-flow environments. Recently, hydrophones with broader frequency bandwidth, higher frequency resolution and increased sensitivity have become available, allowing for “spectral noise logging” (Aslanyan and Davydov, 2012). Another new technology is the geophone noise survey, which consists in deploying an array of sensors downhole and collecting measurements throughout the length of the wellbore. The tools are designed with a hydraulic backup arm that extends to clamp each sensor against the inside of the well casing, acoustically coupling the instrument to the pipe, increasing data quality and improving measurement sensitivity. Consequently, geophones are not as vulnerable to low frequency noise contamination and maintain vertical resolution in the low-end spectrum. First arrival times between sensors can be used to determine the direction of vertical flow behind the pipe. Fiber optic Digital Acoustic Sensing (DAS) tools employ similar measurement principles and are also being used for the detection of wellbore leakage (Hull et al., 2010). The sensors are comprised of fiber optic material wrapped into a physical coiled length, effectively creating a hydrophone but with increased sensitivity and measurement fidelity.

5.1.2 Carbon isotopes

Carbon isotope measurements may be used to identify sources of gas migration. Microbial gases are created by bacterial activity in near-surface soils (Szatkowski et al., 2002). Thermogenic gases are generated by elevated temperature and pressure acting on organic materials at much greater depths. There are two stable isotopes of carbon: ^{12}C with relative abundance of 98.89%, and ^{13}C with relative abundance of 1.11%. By comparing the ratio of abundance between ^{13}C and ^{12}C isotopes in a sample with that of a laboratory-derived standard, the unique isotopic composition (or carbon isotope fingerprint) is characterized. Individual geological formations have distinct carbon isotope fingerprints that vary systematically with depth. Typically, a more negative ^{13}C abundance in the sample indicates a younger, shallower depth of origin. Isotope analysis for wellbore leakage involves comparing the delta value in a production sample with that of a leakage gas sample. It is possible to identify the migrating fluid’s formation of origin using this method (Rich et al., 1995; Szatkowski et al., 2002; Figure 5.1). Isotopes of sulfur, oxygen, and hydrogen are also useful for source identification (e.g. Rostron and Arkadakskiy, 2014) but are not typically used because there is much less information on their stratigraphic and geographic values than there is for carbon isotopes.

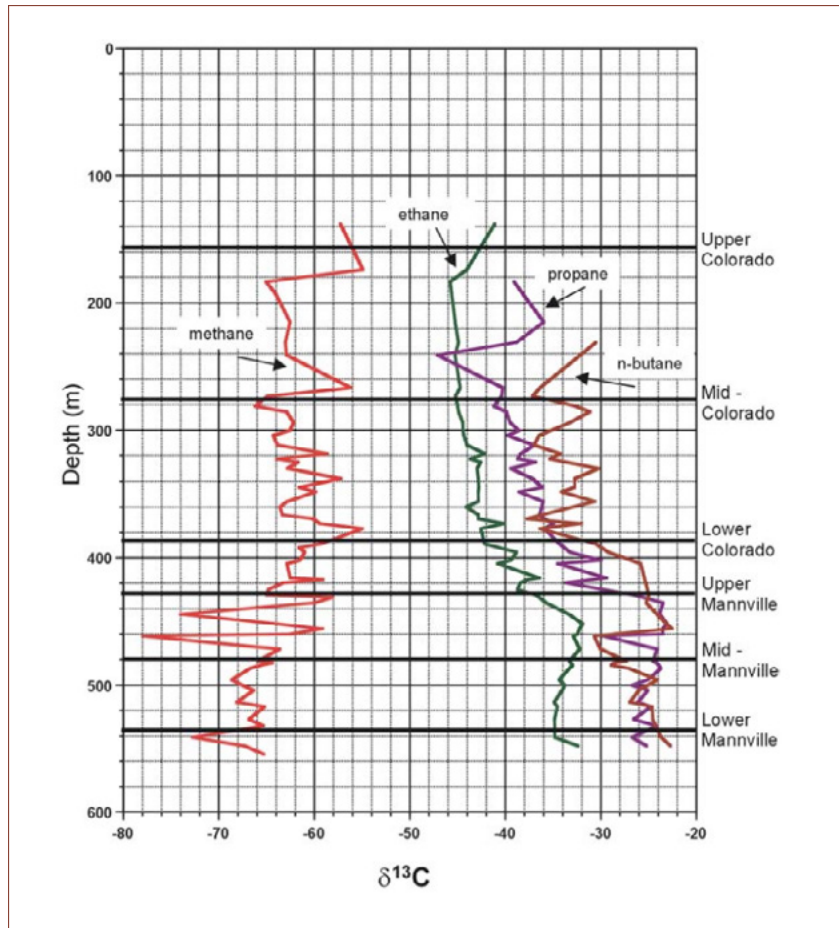


Figure 5.1 Profiles of the isotopic composition of carbon in n-alkane gases collected while drilling a well in west-central Saskatchewan (Szatkowski et al., 2002). By comparing the isotopic signature of gas samples collected from SCVF and GM to that from gas samples collected during the drilling of the well or a nearby offset well, it may be possible to identify the source (and depth) of the leakage gas.

5.1.3 Formation evaluation

Formation evaluation systems (or geophysical logs) were first introduced in the 1930s for the purpose of identifying lithology and formation properties by logging the open hole. For economic or operational reasons, not all wells have lithological data from open-hole logs. Consequently, cased hole formation evaluation techniques were developed in the 1980s to identify areas of gas storage and by-passed pay (Elkington et al., 2006). The use of gamma ray, neutron, density and sonic measurements allows for the classification of wellbore fluid characteristics, petro-physical features and lithology. In the context of leak source identification, these methods can be used to identify gas-bearing formations with potential to be the source of wellbore leakage. These measurements also provide information identifying the caprock formation over which to place the remedial intervention in order to most effectively isolate the source horizon. One advantage to logging in a cased hole is that invasion of drilling mud fluids at the time of open-hole

logging will dissipate as gas gradually migrates back into permeable formations near the well. Gas bearing zones that may have been masked when logged in an open hole will become more apparent in cased hole logs one to two weeks after the casing has been installed.

5.2 Problems with Current Operational Practices

Historically, wellbore leakage intervention has been executed with minimal planning, which usually results in ineffective identification of the leakage source and leak remediation. The efficacy of the remediation is influenced by the available methods of source zone identification, but these also have limitations, as enumerated below.

5.2.1 Acoustic energy

Hydrophone tools were originally designed to detect flow rates on the order of 100 m³/day or greater, much higher than the typical rate of wellbore leakage seen in Alberta today (<1.0 m³/day). They are not sensitive enough to produce reliable results at low rates, and are susceptible to low frequency noise contamination from sources at surface (Maslennikova et al., 2012). These problems are further complicated by variations between service companies in their data acquisition process, hydrophone quality and tool maintenance. All contribute to the perceived lack of quality in the conventional noise log for annular flow at low volumes. Additionally, the calculations for predicting the flow rate from noise amplitude are idealized for specific geometries and known rates that are not likely to be replicated in field applications.

For spectral hydrophone measurements, the discrete frequency bandwidths assigned to characterize flow types are sensitive to flow path geometry and are not always clearly defined. Completion elements can produce uncharacteristically high frequency signatures where poor perforations, packer leaks or casing leaks are present. Frequency varies with flow conduit size and structure. Flow channels can be interrupted by impediments such as cement or formation constrictions, making interpretation difficult. Reservoir fractures may also exhibit frequency characteristics similar to borehole fluid flow or completion elements.

There has been limited experimental testing of geophone response in a laboratory facility; designations of vertical and horizontal flow regimes are based on interpreted field results.

5.2.2 Carbon isotopes

There are a number of issues confounding the use of carbon isotope fingerprints to identify sources of wellbore leakage emissions. The isotopic signature of methane can be altered in the sub-surface due to oxidation and production mechanisms. Oxidizing bacteria preferentially consume the lighter isotopes in methane gas, also affecting ethane isotopic compositions. Propane and butane signatures can often violate the expected order of enriched ¹³C content in co-generated gases by means of reversed ¹³C/¹²C partitioning (Chanton et al., 2005; Rich et al., 1995). The addition of heat in thermal developments can fractionate isotopes, causing their composition to vary.

Surface sample collection techniques, interpretation methods and machine calibration discrepancies can impact analytical results. Sample acquisition may be done using specially designed bags that require timely processing to prevent sample degradation. Pressurized canisters may also be used, but these require sufficient pressure to be filled, a difficult threshold to satisfy given the low flow rates and pressures typical of GM/SCVF. To ensure the concentration of gas in the sample is adequate with respect to the amount of air contamination requires proper training of field personnel.

Isotopic signatures should be compared to samples from the same well—collected from mud gas during drilling. If such samples are not available, wellbore leakage samples may be compared to samples taken from sufficiently close offset wells. The leakage sample origin may be incorrectly identified if fingerprint data is not available within an adequate range. In wells with multiple sources, the isotopic analysis will yield only a value identifying the oldest or deepest source. A comprehensive, standardized database of production horizon isotopic fingerprints does not currently exist for all areas that have wellbores.

5.2.3 Formation evaluation

Formation evaluation in a cased hole is more challenging than in an open hole. For through-casing density and acoustics, pre-job planning and consultation with the wireline service provider is necessary to ensure that the wellbore conditions are favourable. Quality checks should include a comparison of the cased hole responses to a nearby well with open-hole logs, and looking for standard log signatures distinguishing clean formations from shales. Under ideal conditions, it is possible to relate cased-hole gamma ray, neutron, density and sonic log responses to those in the open hole, but ideal conditions are not always available.

Acoustic tools will not work in a gas-filled borehole due to extreme signal attenuation. In general, a liquid-filled wellbore is also required for a neutron tool, although there are air-filled-hole corrections. These corrections may not always work, so the borehole should be filled with liquid if possible. It is also recommended for the casing to be fluid filled for pulsed neutron capture logging. Gas bubbles inside the liquid-filled wellbore can affect measurement accuracy.

Penetration depth is a problem for a number of through-casing logs. For instance, the measurement depth for a neutron log is 9" – 12", and even shallower for density logs. The general consensus is that the density data will be valid in a cased hole when the distance between the tool and formation (standoff) is limited to 1.5" – 2.0" (Ellis et al., 2004; Odom et al., 1999; Sherman and Locke, 1975). For pulsed neutron capture, the depth of investigation is similar to that of the neutron tool, though some of the newer tools with longer detector spacings are capable of up to 14". Density measurements are also very susceptible to hole washouts and rough hole conditions.

In acoustic logging of a cased hole, a secondary requirement is that there must be good cement bonding between the casing and formation, otherwise the compressional wave may respond to only casing or cement. For all logs, wellbore configuration and mechanics need to be understood and carefully characterized. Large wellbores and casing can limit the effectiveness of the measurements.

5.3 Improving Operational Practices with Existing Technology

Current regulations do not specify which source identification technologies to use but do state that acceptable methods include noise/temperature surveys, gas analysis and logs (Alberta Energy and Utility Board, 2003). Best practices for identification of wellbore leakage source zone and intervention interval should include the combined implementation of all tools and technologies currently available to identify fluid movement, escape path, and source zone. Formation evaluation logs identify zones potentially contributing to wellbore leakage gas, while acoustic measurements and isotopic analysis aid in source-zone identification. Cement bond logs can improve the identification of apparent annuli, voids or channels, and can be used for interpretation of acoustic measurements.

Patience must be practised when creating the intervention strategy. Baseline information gathering prior to repair is extremely valuable. It may take several months for gas stored within the wellbore or other shallow zones to dissipate from the well. This is often mistaken for a failed repair attempt. Recording a stabilized pressure build-up on the vent before starting an intervention and comparing to post-remedial build-ups can indicate that an additional intervention is not required. Quick turnaround time to save on rig costs can limit the quality of the interpretation, leading to intervention failure and multiple interventions. This can result in remedial costs reaching into the millions of dollars on a single well.

5.3.1 Acoustic energy

Acoustic energy measurements have the ability to identify gas and liquid movement behind casing and isolate-contributing horizons. However, two aspects of acoustic measurements that need to be better understood in order to improve source identification are the effects of turbulent fluid movement through the escape path and background noise contribution. To mitigate these issues, operators should obtain a current high-resolution cement bond log (to assess variability of the flow path) and perform an assessment of possible sources of acoustic interference (to account for or minimize background noise). Conventional hydrophone tools should not be used to identify sources of fluid migration if the flow rate is relatively low. To create consistent and repeatable results from well to well, a standardized data acquisition procedure should be established.

5.3.2 Carbon isotopes

Similarly, standardized sampling and testing procedures are needed to improve carbon isotope measurements. Current databases have questionable samples that may add significant error to the interpretation of new samples. Samples that have been quality controlled should be added to an openly available carbon isotope database. A comprehensive database of known horizons, preferably single interval production sample fingerprints, will greatly increase the effectiveness of carbon isotope measurements.

5.3.3 Formation evaluation

Formation evaluation data is used to identify the caprock when choosing the intervention interval in the wellbore, and also to identify potential gas-bearing zones. Formation evaluation data does not differentiate which horizon is actively contributing to wellbore leakage. Open-hole and caliper logs provide excellent data and, when available, an open-hole analysis should be performed to identify source zones. Any existing open-hole logs should be compared to the through-casing logs to identify the most likely source contributors, namely non-commercial gas zones that were saturated during drilling and were not recognizable on open-hole logs.

5.4 Knowledge Gaps and Research Recommendations

The following knowledge and technology gaps have been identified as needing more research and development through the application of lab or field studies:

- ▶ **Acoustic energy measurements:** The minimum flow rate that can be accurately detected with each acoustic energy technology should be identified, especially for conventional hydrophones, which continue to be used inappropriately in low-flow settings unsupported by the original research (McKinley et al., 1973). Research should assess the effect of background noise, clearly define the depth of investigation, quantify the effect of multiple casing strings on the effectiveness of the tools, and determine which technologies are best suited for specific areas or wellbore environments. Studies to determine the effects of data acquisition procedures on the measurement quality would be valuable, as would a comparison of the effectiveness of distributed acoustic sensing versus other techniques. Technology and methods to accurately measure acoustic data in larger diameter wellbores are also needed.
- ▶ **Isotopic analysis:** Future research efforts should focus on determining the effects of improper sample collection, improper processing and time delays in testing. The effectiveness of current sample collection techniques, procedures and containment methods should be studied. Changes in isotopic composition as gas travels from source horizon to shallow subsurface horizons and to surface should be quantified and the temperature threshold for isotopic fractionation in thermal environments should be assessed. Finally, comprehensive fingerprint databases with samples of all producing horizons should be developed for hydrocarbon producing regions.
- ▶ **Formation evaluation:** For formation evaluation, an examination of the effects of borehole size and varied lithology on measurement accuracy would be useful, as would a method to differentiate formation gas storage from annular gas storage. Techniques for accurate formation evaluation logs in larger boreholes with multiple casing strings would be valuable.



Remediation Strategies

This section provides an overview of the current state of wellbore remediation, focusing on regulations, technologies and experience in several of the key hydrocarbon-producing regions of the world, while focusing on the Canadian experience. It is a summary of the TRM report entitled *Intervention Strategies to Increase Wellbore Leakage Remediation Success Rates*, produced by Jonathan Heseltine and Todd Zahacy of C-FER Technologies, Edmonton, Alberta.

6.1 Current Practices and Regulations in Well Operation

Regulations governing repair of a leaky well are often not prescriptive. They usually describe broad objectives and do not specify details on where, when and how a leaky well should be remediated. This is reasonable given that each well tends to have unique requirements. The regulations tended to focus on the classification and reporting requirements rather than potential risks or repair methods and are often specific to the local jurisdiction and type of well (e.g. onshore versus offshore). Several of the guidelines and regulations reviewed for this study recommended a risk-based approach to well leakage classification, management and remediation, especially the oil-producing countries in the North Sea region. Most regulations appear to allow for some leakage (or pressure management) during the well's production life, but require complete isolation for abandonment (AER, 2003).

The process for repairing leaks in the annulus of hydrocarbon wells generally involves four steps: (1) identifying the source and a suitable depth for intervention (addressed in Section 5); (2) developing communication (access) to the source/leakage path; (3) sealing the leak; and, (4) verifying operational success. In most traditional methods, communication with the casing-casing or casing-formation annulus is required in order to inject a sealant to plug the leak. Communication is most commonly established by perforating the casing and typically also penetrating the cement sheath and near-wellbore formation layer. Such perforation methods include jet perforation with shaped explosive charges, bullet perforation, abrasive jetting, and high-pressure fluid jet perforation. Other methods for gaining annular communication include casing punching, abrasive cutting (such as circumferential slots, as described by Saponja (1999), and section milling. Considerations when choosing a method include the selected remediation sealant, sealant placement method, wellbore depth interval, radial penetration, and wellbore completion design and casing diameter.

Squeeze placement is the most common method used to place the selected sealant material. The application of an overbalanced pressure on the sealant forces it into perforations, annuli and voids. With Portland cement, the pressure against a permeable formation results in leak-off and causes the slurry to dehydrate, building an impermeable filter cake. A 'circulation' squeeze is similar, with the goal of circulating cement into a channel behind the casing through two sets of perforations. Controlled fracture squeezes have also been successfully applied in calcareous caprock formations penetrated with circumferential jet-cut slots (Saponja, 1999). The practice of squeeze

placement of sealant materials, such as fine particle Portland cements, is generally well developed. The choice of an appropriate method and materials will depend on the downhole environment (geometry, fluids, geology, etc., Watson, 2004; Slater, 2010). Following penetration through the casing and out into the formation, water is commonly injected to clean up the penetrations and to develop a water-permeable communication path to aid in sealant placement. Slater (2010) suggests ultra-low rate pumping of Class G Portland cement at sufficient pressure to create a network of micro-fractures to access and fill all available voids, with pumping continuing until the cement slurry has thickened to discourage gas influx and migration.

In many well completions, the casing is not cemented to the surface or even into the next casing shoe. While this condition presents a potential path for fluid movement, Ness and Gatti (1995) noted that remediation is generally more successful, compared to a fully cemented annulus, since access to the large annular flow path is more easily achieved.

6.2 Problems with Current Operational Practices

Remediation of the annular cement sheath has often proven to be difficult. For example, Saponja (1999) and Wojtanowicz et al. (2001) noted that squeeze cementing success rates were typically only about 50%, both for Husky's wells in the Lloydminster region of Alberta and for offshore wells in the Gulf of Mexico, respectively. A similar number was recently suggested at a workshop on Western Canadian operations (Alberta Innovates—Technology Futures, 2015). Anecdotal evidence indicates that costs of cement remediation can vary from as low as tens of thousands of dollars to millions or tens of millions on problematic wells (Society of Petroleum Engineers [SPE]/CSGM, 2015; Dusseault et al., 2014; Watson et al., 2002). Inadequate identification of the leak source and poor communication with the annular leak path are two of the primary reasons for unsuccessful remedial operations. Remediation materials and methods are also closely linked with well abandonment, as in order to abandon wells with identified behind-casing flows or leaks to surface, these flows must first be eliminated.

Operators and service companies are faced with many decisions during remedial job planning and execution. While industry-recommended practices exist, such as the *DACC Primary and Remedial Cementing Guidelines* (DACC, 1995), the *Best Practice Guidelines for Remedial Cementing* provided within *Well Cementing* (Nelson and Guillot, 2006) and field experience described by Slater (2010), it appears that planning of the remedial operation often relies on the experience of the operator and cementing service companies.

The proper position for an effective seal is also controversial. Current requirements for remedial sealing involve squeezing cement into the leak source formation to stop gas migration at the source. However, the source zone can be difficult to locate (as described in the preceding chapter) and it may be difficult to push cement into the small flow paths (Saponja, 1999) and out into the formation, depending on the petrophysical properties of the rock. As a result, some experts promote the idea of re-establishing a caprock seal above the contributing source zone (e.g. Saponja, 1999), while others contend that caprock repairs are often ineffective, being too far above the source location, and

prone to damage by pressurized fluid (e.g. Perry, 2005). Cement may also not be an ideal material for caprock sealing, as the cement particle size and viscosity inhibits the injection of cement into small fissures and microannuli.

6.3 Improving Operational Practices with Existing Technology

In addition to Portland cement, there are a number of alternate materials being used and developed for annular remediation of leaking wells. These materials include resins and other polymers, silicates, geomaterials, salts and metals. There are several potential benefits of these materials. Many have better sealing properties, including lower permeability, higher tensile strength, lower Young's modulus and improved casing bond. Better fluid rheology and particle size distribution (or no particles) allows many of these materials to be more readily squeezed into small channels. Finally, many of these materials exhibit improved longterm stability—they are claimed to be less sensitive to temperature, load, corrosion or other forms of chemical degradation.

- ▶ **Resins** are among the most widely used alternate sealant materials (Gamache, 1993). Most of these resins are synthetic thermosetting polymers that are mixed as a liquid prior to pumping and undergo an exothermic cross-linking chemical reaction to become a solid. They are commercially available and development for downhole sealing applications is ongoing. According to Jones et al. (2013), some resins were previously incompatible with water, limiting their application. However, newer water-compatible resins have now been applied successfully in the field. The heat tolerance and durability of resins are still unproven for certain applications, such as high temperature thermal recovery wells. C-FER Technologies (Heseltine, 2016) is conducting research to assess the high temperature performance of various resins. The Alberta Energy Regulator is currently investigating the potential risks these materials may pose if used above the base of groundwater protection (CSGM, 2016).
- ▶ **Pressure-activated sealants** are materials that polymerize when subjected to a sudden drop in pressure. Rusch et al. (2004) describe several case studies where such materials were used to seal microannular- or microcrack-sized flow paths to remediate leaking wells. Various placement methods are possible, including placement down the annulus from surface, a costeffective approach compared to methods requiring casing perforation and dedicated downhole tubulars. This approach may provide a method to remediate annular flow to surface while maintaining the casing pressure integrity. However, it should be noted that blocking the flow near surface could result in cross flow between permeable zones downhole or breakdown at the casing shoe. Alberta Energy Regulator Interim Directive ID 2003 01 states that pumping any type of fluid down the annulus is not an approved repair option (AER, 2003).
- ▶ **Sodium silicate** is a general term for a synthetic inorganic colloidal compound composed of negatively charged, nano-sized silicate particles that can be pumped ahead of cement (or other remediation sealants) into very small fissures (such as a microannulus) that even fine particle cement blends may not be able to access. Sodium silicate has been used to remediate gas flow problems for decades (Herring et al., 1984; Borchardt, 1992). The silicate reacts with its surroundings to form a

silica/silicate-based plug that will block the flow of gas or liquids by precipitation, polymerization, bonding to cement and clogging of pores.

- ▶ **Metal alloys with relatively low melting points** have been proposed to replace cement in remedial and well-plugging applications. Such materials would be injected in a molten state and then cool and solidify once placed. In one proposed approach, a bridge plug is set and a molten bismuth-tin (Bi-Sn) alloy is squeezed into perforations at pressures below the fracture pressure (Spencer and Lightbown, 2015; Figure 6.1). The alloy remaining in the wellbore is then milled out. The suggested benefits of metal sealants include strength, durability, low permeability and volumetric expansion upon setting. For such seals, it is suggested that the material be placed over an interval of impermeable caprock, not the permeable source formation. This appears to contravene Interim Directive 2003 01 (AER, 2003), which notes that the sealant should be placed at the leak location.



Figure 6.1 Seal Well alloy deployment tools with bismuth-tin alloy cast on the outside of a cartridge heater. The technology can be used to both seal wells for abandonment and remediate leaky wells. In either application, the tool is lowered onto a mechanical bridge plug and the heater is turned on. The second image is of a wellbore analogue system with an alloy-filled perforation (Spencer and Lightbown, 2015).

- ▶ Various **clastic and geo-materials** have been proposed for well leakage remediation, including grouts, clays and silica-based materials. For example, Saasen et al. (2011) describe the use of an unconsolidated silica material for well abandonment plugging. The material's particle size distribution is carefully controlled and, with water as a bond between the grains, yields a very low permeability barrier (less than 1 mD). Such materials are non-shrinking, self-healing and removable. While suggested as an option for wellbore plugging, such materials are also apparently suitable as a behind-casing barrier (Sandaband, 2016).

- **Permanently expanding the casing** is proposed to remediate microannular flow paths. Kupresan et al. (2014) describe a lab test where expandable casing technology was used to shut off annular flow. In the tests, an inner casing with a manufactured microannulus was expanded beyond its yield point with an expansion cone drawn through the test specimen. Pressure testing showed isolation up to 690 kPa (100 psi) differential over the 24inch-long specimens. They noted that the expansion of the inner pipe caused the fully hydrated and set cement to change into a “paste like” state that could be easily crushed. The cement later “rehydrated” into a mechanically competent material. A tapered cone mechanical expansion system for remediation of behind-pipe casing flow through micro-annuli, termed the ‘SMART Tool’, is also described by Duncan et al. (2016).

6.4 Knowledge Gaps and Research Recommendations

6.4.1 Regulatory

Most oil and gas regulations in Canada require immediate action when wellbore leakage conditions equal or exceed prescribed flowrates, fluid types and pressure buildup rates. Requirements based on fluid type and buildup pressure may be more easily justified, but the requirements based on a specific gas flowrate at one point in time do not appear to consider potential variabilities due to sampling/testing practices (Dusseault et al., 2014) or the leak from a risk-based perspective. A review of these prescriptive regulations may be warranted to determine whether there should be additional considerations when classifying leaks to identify the optimal course of action considering the risks. A risk-based assessment that considers both the likelihood and consequences of undesirable events associated with leakage and remediation might be more appropriate. Such an approach is described in OGP Draft 116530 2 and Norwegian Oil and Gas Association Recommended Guidelines for Well Integrity No 117 (NOGA, 2011). The primary goal of such a risk assessment initiative is to establish acceptable leakage conditions. To provide a context for risk assessment, rates could be compared to other socially accepted natural and man-made methane sources (e.g. agriculture) (Dusseault et al., 2014).

Risk-based assessments and regulations have several benefits: (1) they allow for innovation in the development of remedial methods and materials, which can lead to more effective technologies and reduced costs; (2) they are flexible and can be applied to diverse situations; and (3) by identifying key risks, limited resources can be applied most effectively. While allowing greater flexibility and innovation, regulations requiring fully risk-based decisions have drawbacks. It can be difficult to accurately quantify all risks. In addition, various stakeholders may have different risk tolerances. The best approach may be to provide an approved prescriptive remediation option but allow for risk-based management or innovative solutions to wellbore leakage events. In such a scenario, the regulator may need to establish a thorough structure and benchmark the risk-based approach. Many jurisdictions allow operators to apply for an exemption to prescriptive regulations, with justification. Though not specific to oil and gas, an example of such a regulation can be found in Ontario’s Brownfields Regulation, which governs the management of contaminated sites (Ontario, 2017). This regulation prescribes

generic standards for contaminant remediation, while allowing an alternative risk-based standard that can take into account site-specific characteristics.

A risk-based assessment of wellbore leakage will likely require input from a wide range of industry stakeholders to develop the risk framework, create necessary models, facilitate workshops and interviews, and develop workflows or software tools.

6.4.2 Industry Recommended Practice (IRP) for remediation

Regulations generally provide very limited technical guidance for wellbore remediation. Some practical guidelines do exist (Watson et al., 2002; Slater, 2010), but are not comprehensive. This suggests that the industry should consider the development of an Industry Recommended Practice (IRP) to assist operators and regulators in evaluating and classifying leaking wells and identifying options for remediation. This approach is common in the industry, where regulations state the minimum requirements and technical guidelines to provide assistance for planning, decision making and conducting operations.

Remedial practices were to be discussed in API *RP 65-3 Practices to Prevent or Remediate Annular Casing Pressure*, although it appears that this document is not yet available to the public (API, 2006). The Drilling and Completions Committee (DACC) plans to establish practices for remedial cementing in the future (DACC, 2016). An expanded remedial cementing IRP, preferably supported by broadly shared industry data, would be beneficial to provide additional information on intervention and remediation topics such as:

- ▶ Decision making and management processes associated with remediation (e.g. risk-based flow chart or ranking considerations);
- ▶ Choosing an appropriate cement slurry or sealant material;
- ▶ Determining appropriate remedial job parameters (rate, pressure, method and completion);
- ▶ Source identification methods;
- ▶ Identifying and selecting an appropriate depth interval for perforation/remediation;
- ▶ Alternate methods for repair and management of wellbore leakage;
- ▶ Descriptions of available alternate materials or methods for downhole remediation and where they should be considered or avoided. Note that the regulations reviewed generally refer to Portland cement as a squeeze material although the AER appears to be accepting of alternate materials, if proven to be suitable (CSGM, 2016);
- ▶ Considerations for specific well applications (multi-stage fracturing, thermal recovery wells, storage wells, CO₂ sequestration wells, geothermal wells, etc.);
- ▶ Data collection, validation, management and application (e.g. consistent parameters and methods for determining success rates, tracking costs and consequences); and,
- ▶ Post-job assessments and long-term well management.

One challenge often noted in the industry related to the development of remediation and/or abandonment guidelines is that there is significant variation across applications and thus a need for specific case-by-case practices, materials and technologies. As

a result, there is concern that the effort to create a comprehensive IRP may be too great or the resulting IRP may be too generic to be useful. In this case, an IRP for well remediation may provide only guidance on the decision-making process, rather than prescriptive requirements or specific “step-by-step” instructions. Such a guideline may also expand on other sections examined with this TRM, such as leak source location and measurement of leakage rates.

6.4.3 Technology gaps

Remediation of wellbore annular leaks often requires multiple costly attempts—typically cement squeezes. Materials and methods that improve short-term and long-term success rates would provide economic and environmental benefits. Development of remediation and abandonment technology has lagged behind other areas such as drilling, completion and production, likely in part because it does not generate revenue (National Petroleum Council [NPC], 2011). Nevertheless, novel methods and materials are being investigated and developed. These include improved methods for establishing hydraulic communication with the leak path and placement of sealants. Many of these technologies appear promising, warranting further research or funding. These technologies must meet a large number of operational and functional requirements, as well as Health, Safety and Environment (HSE) regulations during blending, placement, post-placement, and after well abandonment. Government and industry should consider developing protocols and methods to consistently assess and qualify the suitability of these technologies. This would benefit product vendors, users/operators, and regulators. For example, the United Kingdom Oil and Gas *Guidelines on Qualification of Materials for the Suspension and Abandonment of Wells* (Oil & Gas UK, 2012) considers the qualification of materials other than Portland cement for wellbore abandonment. While aimed at abandonment materials (typically for plugging tubulars), many of the objectives and requirements are similar for annular remediation materials. The guidelines provide a starting point for establishing qualification standards of remedial material properties and methods.

For qualification of equipment and placement methods, large-scale functionality tests may be employed (similar to API and ISO protocols and standards available for packers, bridge plugs, connections, and float equipment). However, existing qualification procedures may not be applicable to all new technologies or methods. Development and qualification may rely on engineering analysis or numerical simulation in addition to physical testing. For example, with the casing expansion methods for microannulus remediation under development, consideration should be given to determining the proper amount of expansion for given tubular/cement/formation scenarios. Over-expansion could potentially result in cement cracking, making a leaking well and associated risks more severe. Numerical modelling could be used to understand the sensitivity to various parameters (e.g., Duncan et al., 2016). Determining microannulus size in the field may require the development of novel measurement methods, for example by wellbore testing or logging.

It should be noted that in the test described by Kupresan et al. (2014), an outer pipe provided considerable confining pressure on the cement during expansion. If this technique is to be used for cement sheaths against weak or shallow formations, the

performance should be evaluated where significantly less confining pressure is possible or expected. At the TRM Workshop (CSGM, 2016), it was noted that new technologies based on this concept are being developed in Canada. One such method being developed by Suncor (Duncan et al., 2016) was recently presented; it described the numerical design optimization and lab validation of a casing expansion method.

Qualification methods (e.g. small-scale material testing, modelling, large-scale testing) may initially be established to address a particular technology and field application. Where applicable, these methods may later be developed into broad industry standards. The qualification of methods and materials requires a thorough understanding of the downhole environment, which includes geology, leak path geometry, temperature, pressure, load profiles and chemical composition. The development of improved methods to evaluate and document these downhole conditions and include these considerations in the technology qualification is suggested.

Remediation of caprock leakage is of potential interest in some wellbore applications such as the underground storage industry and possibly to other CO₂ sequestration and thermal recovery operators. This area appears to require additional research and the development of suitable methods and materials. Some jurisdictions allow for the control and remediation of annular pressure using surface methods, such as injecting down the annulus. A review of these alternative methods and associated risks is suggested.

6.4.4 Remedial data analysis and sharing

Wellbore leakage is an industry-wide problem. Improvements in remediation efficiency, success rate, reliability and cost would benefit all stakeholders. The outcome of remedial efforts (such as squeeze cementing) depends on many factors. Given the large number of variables, improvements to the process of leaky well remediation have generally been made after a lengthy and costly trial and error approach. The industry may benefit from a consistent method of tracking and sharing information related to wellbore remediation. If this effort results in improved performance, accelerated development and reduced costs, operators may be motivated to share both successes and failures. A data analysis and sharing platform would provide a method for thorough, consistent post-remediation assessments and long-term tracking across the industry. Such an industry database could be developed by the regional or national regulators or through a shared industry initiative managed by a third party (AER, 2017).

Dusseault et al. (2014) noted that there has likely been an under reporting of unsuccessful remedial attempts. As a result, the industry does not have a thorough understanding of which methods work best and, equally important, those that do not. Tracking of successes and failures would provide statistical information, perhaps leading to better understanding of the problems, accelerate technological improvements, and provide valuable inputs to industry guidelines, recommended practices and risk-based assessments. The sharing of information may take the form of a shared, searchable database that tracks key parameters. This database could also contain other well integrity data to serve a larger purpose.



Abandonment

The goal of wellbore abandonment is to restore the low permeability of the caprock formation preventing fluid migration in the wellbore and near wellbore region. The following sections identify general methods of wellbore abandonment and problems with the current approach, and make recommendations for future research. This is a summary of the TRM report entitled *Improving Abandonment Processes*, which was written by Robert Walsh and Dru Heagle, Geofirma Engineering, Ottawa, Ontario.

7.1 Current Practices and Regulations

When crude oil and natural gas drilling began in the mid-nineteenth century, there was no regulation regarding abandonment of a well at the end of its production, and operators could simply walk away from an open hole in the ground. In the 1890s, plugging and abandonment regulations were instituted in some jurisdictions, with the goal of protecting production zones from flooding by freshwater (Pennsylvania Department of Environmental Protection, 2000). Typically, earlier plugging operations were designed to prevent the loss of crude oil and natural gas to other formations, to protect the resource, not the environment. In the United States, early regulations enabled wells to be plugged with “brush, wood, rocks, paper and linen sacks, or a variety of other handy items that would serve to hold a sack of cement” (NPC, 2011), which is consistent with anecdotal information regarding re-abandonment operations on wells drilled before 1950 in Alberta and Ontario. As regulations improved, cement became a required material for sealing the producing intervals and the top of the wellbore. Over time, plugging regulations have progressed to describe the specific intervals at which cement should be placed and the types of materials allowed between the cement plugs. The basic technology associated with the plugging and abandoning of wells has not changed significantly since the 1970s (NPC, 2011).

7.1.1 Current oil and gas abandonment practices

An abandoned wellbore commonly comprises a surface casing that extends below the base of potable groundwater protection and a production string, or multiple production strings, that access the target formation. The annular spaces between casing and formation, and between different casing strings, are cemented or at least partially cemented. The typical abandonment approach is to emplace cement plugs (typically API Class G cement), which may be supported by mechanical plugs, within the casing or in the open hole if the well is uncased (e.g. core and delineation wells). To properly abandon a well, the well operator must design an abandonment program that identifies wellbore integrity issues, crude oil and natural gas zones, groundwater zones, and cement integrity. The basic steps of the modern abandonment process are described as follows:

- 1. Test for SCVF/GM:** Hydrocarbon wells may develop wellbore leakage either over time or relatively soon after construction. In Alberta, prior to conducting a surface abandonment, a surface casing vent flow test is conducted to determine if gas, liquid or any combination of substances is escaping from the casing vent assembly (AER, 2003). If such a leak is identified, the problem must be remediated prior to abandonment (see Section 4).
- 2. Prepare the wellbore:** Before abandonment, production tubing, downhole pumps and packers must be removed. Following removal of downhole equipment, the borehole must be cleaned, by flushing the wellbore with a circulation fluid—typically water. If sealing an uncased well, it is important to remove the mud and mud cake from the zones of the wellbore where cement will be emplaced. In a cased borehole, hydrocarbons should be removed to ensure the casing is water wet, allowing cement to bond to the casing.
- 3. Plugging:** Cement plugs in open holes or within cemented casing are emplaced under a variety of conditions and using various methods. Cements can be placed in single or multiple stages in the borehole depending on the requirements. In uncased boreholes, the most common method for cement plug placement is the balanced plug method. In Alberta and other Canadian jurisdictions, cased wells classified as low risk are usually plugged by dump bailing 8 m of cement on a bridge plug installed in the casing (AER, 2016b; Figure 7.1). In addition to cement plugs, mechanical plugs such as bridge plugs and cement retainers play a role in stopping fluid flow in a wellbore. Where there is no cement behind the casing, or the cement has been identified as inadequate, it may be necessary to remediate the annulus cement to isolate permeable zones (see Section 6). Testing is required to ensure that the plug is placed at the proper level and provides adequate isolation of permeable zones.
- 4. Cut and Cap:** The final field-step of the abandonment process is to cut and cap the well. Typically, the casing string must be cut off a minimum of 1 metre below the final grade of the site. Before the well is cut and capped, the presence of wellbore leakage must be determined, as described above. In Alberta, a vented cap is required to prevent pressure buildup in the abandoned well. Other jurisdictions, especially in the United States, require a sealed cap.

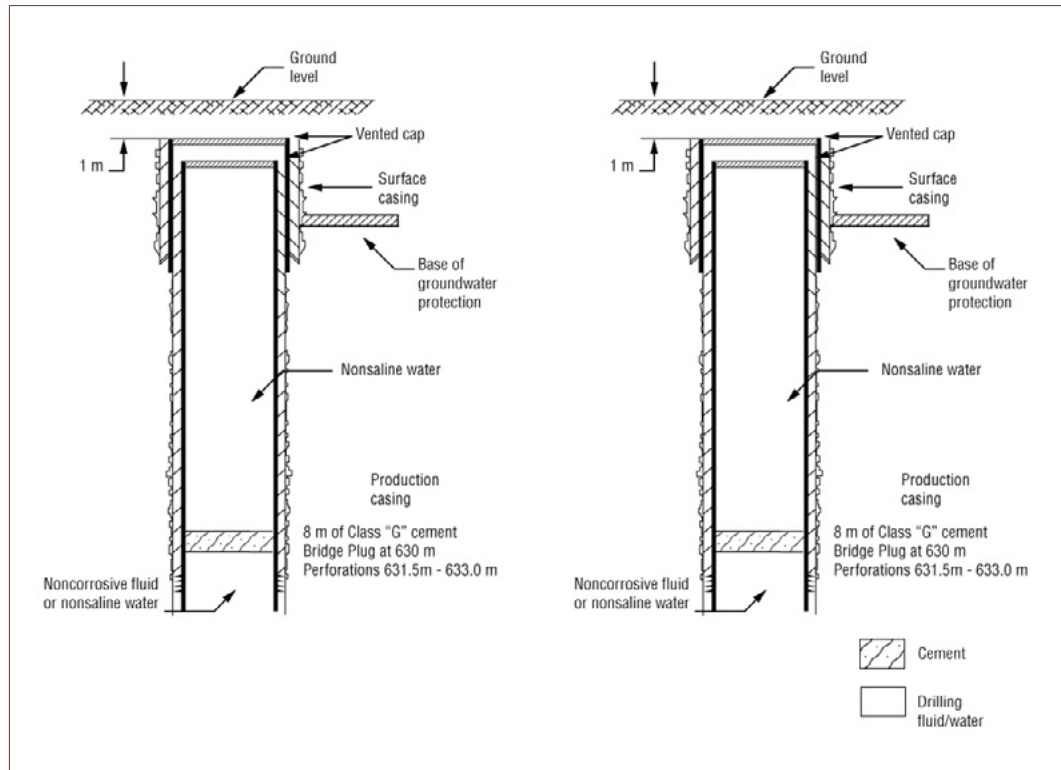


Figure 7.1 Examples of cased-hole abandonment for low-risk wells (AER, 2016b).

7.2 Problems with Current Operational Practices

Abandoned well failure modes can be divided into two broad categories: (1) inadequate sealing and leakage of plugs within the casing; and, (2) inadequate sealing of the (usually cemented) annulus, outside of the casing. The following sections discuss both possibilities.

7.2.1 Inadequate sealing of the annular space

As discussed in previous sections, the failure of annulus seals is primarily the result of poor mud displacement during cementing, gas migration into cement during setting, microannulus or stress crack formation during operation, or autogenous shrinkage during cement hydration, leading to the formation of a microannulus (Dusseault et al., 2000; Zhang and Bachu, 2011). Nygaard (2010) observed that cased wells seem to be more prone to leak than drilled and abandoned open-hole wells, and injection wells were more leak-prone than production wells. Research suggests that permeable interfaces (microannuli) or problems with cement placement are responsible for the creation of permeable flow pathways in the cement sheath, rather than degradation of the cement itself (Duguid et al., 2013; Gasda et al., 2013; Crow et al., 2009). Based on current abandonment practices, problems with the cement sheath may continue to impact wellbore integrity post-abandonment. Even if a bridge plug set inside the casing never degrades, the cement plug inside the casing provides a durable seal and the casing never corrodes, an inadequately sealed cement sheath will still allow fluids to migrate.

7.2.2 Inadequate plugs inside the casing

In a study of abandonments in Alberta by Watson (2005), fourteen abandoned wells were investigated to determine the long-term effectiveness of wellbore abandonment methods. Less than half of the wells had been abandoned for more than 15 years, and only three had been abandoned for more than 20 years. The small sample cannot be considered statistically representative of the population of wells, but the results are nevertheless instructive. Of the re-entered wells, two wells had SCVF upon re-entry, but GM was not detected in any well. Only 60% of the wells had corrosion inhibition, a requirement at that time they were abandoned. Only 50% of the wells had the required cement cap on top of the bridge plug. The investigators state that there was evidence that the cement plug was placed, but never developed sufficient compressive strength, and was circulated out of the hole upon re-entry. The one open-hole cement plug encountered in the investigation did not meet the minimum requirement that it extend 15 m below the surface casing shoe, though a plug log run at the time of abandonment indicated that it did extend to the required depth (before setting). Encouragingly, all of the mechanical bridge plugs set in the casing were still providing an effective seal at the time of re-entry.

This study highlights two potential problems with how wellbore abandonment is practised today. The lack of inhibition in a large number of wells suggests that regulatory requirements were not being met. The extremely poor-quality cement in 50% of the dump-bailed plugs also suggests that the proper cement placement procedure was not being followed. The authors estimated that 10% of these plugged wells would fail over the long term and recommended using a balanced plug method or setting a retainer and squeezing the cement as better alternatives. In a recent communication, the author of the abandonments study (Watson, 2005) asserted that it is not possible to consistently achieve good-quality dump-bailed cement plugs because the method is fundamentally unsound (Watson, personal communication, 2016). If we take as a given that dump-bailed cement plugs frequently provide no mechanical strength or hydraulic barrier (because in many cases the cement does not even set), it might make more sense to change the recommended approach for wells categorized as low risk. Watson advocates using only mechanical bridge plugs in low-risk wells (i.e. sweet shallow gas), and that much longer (~100 m) cement plugs be circulated into place in higher risk abandonments.

7.3 Improving Operational Practices with Existing Technology

There is a great deal of existing technology that can be used to improve the performance of abandoned wells, reducing the rate of GM and SCVF, and improving the durability of well sealing systems. This section briefly summarizes various options.

7.3.1 Improving completions

Existing technology can be used to improve the performance of abandoned wells, and this begins during installation of the casing, long before the well is abandoned. This topic is covered in Section 4.

7.3.2 Casing removal/annulus sealing

Recognizing that many of the problems in wellbore abandonment occur behind the casing, a number of authors have suggested that milling out or otherwise removing a section of casing and annulus cement should become a standard practice in wellbore abandonment (Gray et al., 2007; Carlsen and Abdollahi, 2007). As early as 1999, Husky Oil (Saponja, 1999) proposed an “economical cap rock repair” solution to the problem of gas leakage which relied on milling out slots and then fracking with liquid cement to induce horizontal fractures cutting off gas migration, regardless of the local stress regime. This type of remedial method is controversial, as discussed in Section 6.2.

7.3.3 Mechanical plugs

Two common types of mechanical plugs are bridge plugs and cement retainers. Bridge plugs are typically made of cast iron with an elastomer sealing element. Bridge plugs are effective for sealing the wellbore from upward gas migration, to minimize penetration by gas of a cement plug during setting, and to minimize contamination of the overlying cement plug. Bridge plugs can be designed to be easily drillable or made to be more permanent. It may be possible to obtain copper bridge plugs for greater corrosion resistance. Cement retainers are used to form the top seal of a plug and allow cement to be emplaced below the retainer. Cement retainers are effective when higher cement pressures are required to plug zones (Slater, 2010). They are typically made of drillable material to enable re-entry of wellbore as needed. Once the tool is set in the well, cement can be pumped through the retainer to squeeze cement. Once the cement is squeezed below the retainer, the tubing is retracted and a mechanical flap closes to seal the cement below the retainer. Cement may be placed on top of a retainer to provide a more complete seal. Arguably, a cement retainer topped by a concrete cap could also be used to emplace a bentonite slurry, perhaps with suspended particles of compressed bentonite.

7.3.4 Improving cement

Cement and cementing practices used in completion and plugging and abandonment of crude oil and natural gas wells have improved over the past few decades, and there are constantly new developments in cement technology. This topic is considered in Section 4.

7.3.5 Bentonite and other sediment-based materials

Historically, bentonite-based drilling mud has been used to plug many wells, relying on the downward pressure exerted by the weight of the mud column and the gel strength of the mud. Sodium bentonite pellets have become more commonly used to seal wellbores since 2000, especially in more shallow wells (i.e. ~500 m deep). Swelling clays offer advantages over cement, including the ability to swell, deform and self-seal. In many cases, bentonite may also be a more economical sealing material than cement, though it may be difficult to emplace at the correct depth before it swells. Under specific conditions, the use of bentonite pellets to plug wells in the Bakersfield and Coalinga Districts of California is approved.

Sandaband® is a 'dry' mix of bentonite clay, barite, and up to 75% quartz sand that has been used in the North Sea for well plugging applications (Saasen et al., 2011). Adding water and viscosifiers with dispersants to the mixture results in a plastic-like material (Bingham plastic) that behaves as a liquid when pumped but then returns immediately to a solid when at rest. Sandaband is incompressible and gas-tight, does not shrink or fracture, and appears to be chemically stable over time. Although barite has a low solubility, there may be a longterm loss of barite through diffusion of dissolved barite.

Quellon HD is a commercially available bentonite mixture made of bentonite pellets (~90%) and magnetite (~10%) (AMEC, 2014). The magnetite increases the density of the mixture. Before hydration, the bulk density of the Quellon-HD pellets is 1,400 kg/m³, increasing to 1,880 kg/m³ after hydration in the borehole. In laboratory tests, the permeability of Quellon HD under a compaction pressure of 190 kPa and a differential pressure 100 kPa was $6 \times 10^{-19} \text{ m}^2$ (0.0006 mD). Quellon HD has been pumped into boreholes without problems. Interactions between magnetite and the iron casing have not been assessed in the available references.

Sealing systems for nuclear waste repositories, including abandoned site characterization boreholes, have focused significantly on bentonite as a sealing material (AMEC, 2014). Many organizations responsible for sequestration of nuclear waste have studied bentonite-based seals. As a typical example, the SKB design requires seals to have a life of at least 100,000 years and has focused on smectite-rich natural bentonite MX80 because of the low permeability and the longevity of the clay's desired properties, particularly the fact that, unlike cement, bentonite will not crack over time.

7.3.6 Resins

Resin-based sealants may be used for applications that require a relatively high mechanical strength. The resins may also be more elastic than cement and may be better suited for situations with varying pressure and temperature (see Section 4.3). Pumpable resins have a controllable range of density, viscosity and curing time, and are reported to be impermeable to gas flow. Resins are not sensitive to hydrogen sulphide or carbon dioxide and do not degrade like cement may. Long-term resistance to elevated temperature, however, is unknown (Heseltine, 2016).

There are three general categories of resins, including epoxies, phenolics and furans, each with advantages and disadvantages. Epoxy resins typically have the greatest bonding strength but relatively fast curing times. Phenolic resins typically have higher thermal stability and easier to control curing time, but have higher viscosity and greater health, safety and environmental concerns. Furan resins allow better control over resin maturation time compared with epoxy resins and lower viscosity, allowing better penetration of narrow fissures and pores, but may shrink during curing.

Resin applications are typically carried out in low volumes due to the relatively high cost per volume and because the immature resin is viscous and can be placed only at a slow rate, which is complicated given the fairly fast curing time. The subsurface temperature is another significant factor affecting curing time. The immature resins are highly reactive, which may cause a problem if the resin is injected into the formation and geochemical reactions inhibit the polymerization (curing) reactions. Resins also have a

high unit cost and if the resin cures prematurely, then the tubing used to inject the resin will likely have to be decommissioned. Resins have been used in proprietary blends with cements and are used with other plugging materials to create a sealing system for a borehole. Solid fillers, such as silica flour or calcium carbonate, may be added to resin mixtures to reduce cost, increase mixture density or provide higher thermal stability.

7.4 Knowledge Gaps and Research Recommendations

Sealing materials for well abandonment must create a seal that is effective over the long term. The sealing material will likely have to be pumpable to emplace the material at the necessary depth in the borehole and the material will need to have a low viscosity before it sets or cures so that the plug is able to access and seal small pathways that may exist outside of the casing. The material must have a sufficient strength to withstand subsurface pressures but must also be flexible enough to deform as required and maintain a bond with the casing and bedrock. The material should maintain enough strength and not shrink while it cures (or afterwards) so that gas channels or other permeable pathways cannot form. Over the long term, the seal must be resistant to corrosion, expansion and contraction, as well as thermal degradation. The material should also be mixable with additives to control the density and set time of the mixture and should be usable in sufficient volumes to create a long enough seal.

In addition to the ongoing development of the materials described in Section 7.3, a number of innovative technologies, at various stages of development, have been identified. These potential options are briefly summarized here:

- ▶ **Thermal sealing** is the application of very high temperatures downhole to heat and melt casing, cement sheath and rock, forming what is presumably a homogeneous and impermeable seal after it cools and solidifies. Baker Hughes (2015) proposes the use of a high-powered laser run in on a wireline. Interwell (2015) is developing a method in which it ignites a heat-generating thermite mixture that generates temperatures of up to 3,000°C downhole. In August 2016, Interwell tested this technology in two wells in Alberta. Approaches involving molten rock have also been assessed for sealing wells for deep well disposal of radioactive waste. Gibb and Travis (2015) describe the development of a “rock welding” technique in which downhole electrical heating was used to melt crushed granitic rock taken from the host formation. According to the authors, this forms a continuous seal virtually identical to the host rock. Unanswered questions include: (1) Could contraction and cracking of the molten mass during cooling be a problem? (2) Does a thermally damaged zone develop in the surrounding, unmelted rock formation? (3) Could boiling pore water or expanded pore fluids in very low permeability formation material, such as caprock shale layers, hydraulically fracture adjacent rocks?
- ▶ **Molten materials** that solidify to form a seal have been proposed by a number of authors. Nygaard (2010) endorsed using a molten metal alloy that expands slightly upon cooling for sealing wells at the Wabamun CO₂ Sequestration Project. Kunz (2016) proposed the use of a molten salt mixture as a seal for borehole abandonment. As discussed in Section 6.3, a report by Spencer and Lightbown (2015) evaluated Bismuth-Tin alloys as a plug material. The alloy evaluated in this

report had a melting point of 138°C. To place the seal, solid Bismuth-Tin alloy can be placed on or in a wireline electrical resistance heating tool. Because the alloy expands slightly (~1%) when it solidifies, it should form a tight seal against the borehole walls, assuming adequate pressure is applied to the plug during cooling (Figure 6.1). This method has been field tested, with reportedly successful results. In an alternate method, Bisn Tec (2014) proposed the use of a thermite heat source to melt Bismuth/Germanium alloys to form plugs in deep boreholes.

- **Casing expansion** uses a packer-like or other device to apply enough pressure to the inside of the casing to permanently expand it, compressing the cemented annulus and closing any microannuli. Kupresan et al. (2014) examined the use of expandable casing technology and found that a modest amount of expansion was able to effectively seal the microannulus. They reported that five days after the expansion, the damaged cement “re-hydrated” into a solid state, regaining its strength. Whether this effect occurs in much older cement in a wellbore environment is unknown. Winterhawk Well Abandonment (2016) is developing a well abandonment technology that will use casing expansion to close the microannular leakage pathway while also leaving a durable plug inside the casing. The technology uses an expanding ring packer and modified asphalt (manufactured for road construction) to form the seal. In laboratory testing, casing expansion of 0.4 mm has been achieved.
- **Engineered biomineralization** is a technique that takes advantage of the ability of microbes to change the chemistry of their environment as they metabolize a food source. Cunningham et al. (2014) described lab-scale experiments in which the permeability of fractured and intact Berea sandstone under very high pressures (1100 psi) was reduced by more than two orders of magnitude following repeated applications of a solution containing bacteria, urea and dissolved calcium. A follow-up paper by Phillips et al. (2016) described the results of a field test of this method in which injectivity was reduced by a factor of approximately four. The advantages of this approach are that the injected solution can reach much smaller fissures than cement due to its much lower viscosity and smaller particle size (the microbes are 2-5 µm in diameter). The disadvantage seems to be the requirement for multiple applications over a number of days, and the uncertain durability of the calcium carbonate precipitate as the pore fluid reverts to natural conditions once a food source is withdrawn. Nevertheless, this method is still in an early stage of development and seems to offer some promise for sealing small permeable features, such as microannuli.
- **Bentonite placement** in boreholes is an ongoing area of research (see Section 5.3.5). Although bentonite has excellent properties for creating borehole seals, one of the challenges associated with bentonite is how to emplace it at the desired depth and with sufficient swelling pressure to create a low permeability seal across the borehole. Another challenge with bentonite is the decreasing swelling potential with the increasing water salinity. The more saline the groundwater, the less the clay swells, which may result in an incomplete, relatively permeable seal. However, with an adequate design, it should be possible to create an effective bentonite-based seal even in a saline environment.

There are many requirements for a good sealing material or combination of materials. As highlighted in the previous sections of the report, there are many methods, techniques and materials that hold promise for improving wellbore abandonments, and there is a substantial amount of research and development looking at new methods and materials for plugging and abandonment. The problem is that these materials are not moving from the development stage and niche applications into wider usage. Even alternative approaches that have existed for some time have not gained wide adoption. This suggests that there is a certain amount of conservatism and perhaps reluctance among operators and regulators, and that this may be inhibiting progress in improving standard abandonment methods. This skepticism may be warranted by a lack of independent and publicly available assessment of the claims made by commercial oilfield service companies or entrepreneurs, and a lack of testing and endorsement by regulatory authorities. However, there are no standard test procedures that can be used to qualify a given plugging technology, although UK Oil and Gas *Guidelines on Qualification of Materials for the Suspension and Abandonment of Wells* (Oil & Gas UK, 2012) provide standards to qualify alternate materials for wellbore abandonment.

If standards are developed, materials can be tested for specific properties such as mechanical strength, corrosion resistance, ductility, long-term durability, and other properties. It may be difficult to develop clear standards based on our current level of understanding of key processes in plugging and abandonment. For new systems, such as the casing expansion plug or the biomineralization technique, it will not be possible to develop a standard suite of tests to qualify these systems. These technologies need independent assessment using well-designed testing programs, such as independently supervised field trials comparing the performance of current and new well abandonment techniques. Furthermore, leakage at a particular well cannot be predicted a priori; these trials should occur in formations where there is a high probability of leakage (for instance, the Lloydminster area might be appropriate) and with a sufficient number of wells to provide statistically meaningful results.

The results of this assessment should be made public. Such third-party R&D would greatly improve industry practice because it would be based on proven results rather than informed intuition. Properly designed, independent research would also provide a justification for regulators to endorse and allow new abandonment methods. Development and validation of numerical models of wellbore plugging and abandonment systems should be part of any independent research program, for use as a tool to aid in the early evaluation of new methods. Such independent tests would likely identify technology gaps for investigation in a second phase of R&D.

The deep geological sequestration of carbon dioxide and radioactive waste has resulted in research into the long-term performance of abandonment techniques for boreholes in these settings. It may be possible to apply the work carried out in carbon dioxide and nuclear waste sequestration to provide workable and economic solutions to abandonment practices in the oil and gas industry. In and near nuclear waste repositories, borehole sealing approaches typically follow a multi-component, multiple barrier seal design. This design philosophy might inspire new approaches to improve the robustness of hydrocarbon well abandonment seals, while keeping costs under control.



Improving Industry Knowledge, Best Practices and Regulations to Reduce Wellbore Leakage

This section provides information on how to reduce wellbore leakage by improving the generation of industry knowledge, transferring and sharing this knowledge, including in formalized best practices documents, and how regulations can be improved by both industry knowledge and best practices. Industry knowledge, best practices¹⁶ and regulations have a hierarchal relationship. Industry knowledge is a collection of processes and technology established by either research and development, or trial and error methodology. Best practices, such as those developed by the Drilling and Completions Committee (DACC) Industry Recommended Practices (IRPs), and the Canadian Standards Association (CSA), are initially started by gathering industry knowledge by willing and pertinent stakeholders to formalize the knowledge into a publicly available document. Regulations, both provincial and federal, are typically the minimum threshold or standard for compliance acceptance.

Historically, getting any large industry, including the oil and gas industry, to cooperate and share knowledge is highly improbable. Exploration and production (E&P) companies are in competition with each other to retain perceived competitive advantages, lower costs and improve rates of return. E&P companies are segmented by types of production, differing well types and provincial boundaries with regulations that are not unified across Canada.

In the wellbore leakage domain within the oil and gas community, the competitive advantages are greatly reduced by the requirement to remediate leaking wells in an efficient and cost-effective manner. As an E&P company solves its wellbore leakage issues, there is a corresponding reduction in liabilities, which does lead to an improvement in shareholder value.

This is a summary of the TRM report entitled *Improving Industry Knowledge, Best Practices and Regulations to Reduce Wellbore Leakage*.

8.1 Landscape of Wellbore Leakage

There are four major segments of stakeholders with respect to wellbore leakage: the general public; the oil and gas industry; research and development groups; and government regulators. This diverse group of stakeholders makes efficient communication difficult.

¹⁶ The term *best practice(s)* is used here as a general term to describe formally documented practices recommended by the industry and is equivalent in purpose to other terms such as *Industry Recommended Practices*.

8.1.1 Wellbore leakage knowledge and information groups

In addition to these four main segments, wellbore leakage knowledge and information groups can be sorted into the following categories:

- ▶ Wellbore leakage interest groups
- ▶ Industry groups that cover wellbore leakage
- ▶ Abandonment interest groups

Wellbore leakage interest groups are quite limited due to the specificity of the subject. The Canadian Society for Gas Migration (CSGM), now called the Well Integrity and Abandonment (WIA) Society, was created to address leaky wells. The CSGM's mandate was to share industry knowledge and technology to reduce and eliminate wellbore leakage. In 2017, the CSGM expanded its scope to include well integrity and abandonments with the associate name change. Petroleum Technology Alliance Canada (PTAC), through its Alberta Upstream Petroleum Research Fund (AUPRF), provides industry-directed funding through a volunteer levy that is collected by the Alberta Energy Regulator (AER).

As in any industry, there are informal groups that gather to discuss problems in that industry. These are often difficult to find and may be part of informal networks that will be discussed in the Industry Knowledge section.

Industry groups that will cover wellbore leakage as part of their general coverage to members are societies and associations such as the Canadian Association of Petroleum Producers (CAPP), the Canadian Heavy Oil Association (CHOA), the Petroleum Services Association of Canada (PSAC), the Canadian Institute of Mining, Metallurgy and Petroleum (CMI), PTAC, the Canadian Well Logging Society (CWLS) and the Society for Petroleum Engineers (SPE).

Abandonment interest groups would include both the WIA Society and PTAC/ AUPRF, as discussed above. Abandonment interest groups would typically include wellbore leakage topics in Canada. Wellbore leakage is usually handled at time of well abandonment, as discussed in a later section.

The industry groups listed above would also cover abandonment topics when the interest of their memberships dictates.

8.1.2 Overview of industry segments in wellbore leakage

The upstream oil and gas industry in Canada is split into three major segments with respect to wellbore leakage:

Exploration and production (E&P) companies acquire the right to drill for hydrocarbons from the respective government body. E&P companies vary in size, from very small or micro junior up to global super major. This diversity of size is unique to Canada as most other countries have their hydrocarbon production dominated by global super majors. Historically, E&P companies have placed minimal attention on repairing surface casing vent flows and abandonments since this business segment was viewed as a cost centre with no revenue generation.

Service and/or technology Companies in the Canadian upstream oil and gas industry are often considered to be the drivers of technological growth. This is especially true for the wellbore leakage segment. Service companies view the wellbore leakage segment as an opportunity for revenue generation that is reasonably stable in an industry where other service segment activity is highly variable in response to commodity pricing.

Abandonment consultants are often relied upon to fix wellbore leakage. Wellbore leakage is typically handled by the abandonment business unit of the E&P company. The majority of wellbore leakage is categorized as non-serious and repair can be deferred to abandonment. Until the last few years, most abandonment teams consisted of consultants with specialized skill sets. The specialization included both knowledge of the abandonment, gas migration and surface casing vent flow regulations, and executing field operations.

8.1.3 Large and small E&P company differences

Large and small E&P companies have inherent differences that arise from the way companies need to operate their businesses. When it comes to wellbore leakage, all companies have issues dealing with this problem.

There is a perception by the general public that the larger E&P companies are the most advanced and innovative due to large research and development budgets. While this may be true for the exploration and production segment of the industry, the R&D budget has rarely filtered down to the abandonment segment.

Large E&P companies have an inherent disconnect between senior management and the abandonment business unit. This disconnect is due to layers of management between the two groups and a corporate structure that is not conducive to communication around abandonments and wellbore leakage.

In the last three years, large E&P companies have made improvements to their wellbore leakage and abandonment management due to the following reasons:

- ▶ Changes to regulations and financial accounting that requires fiscal accountability to the liabilities of corporate assets (asset retirement obligations).
- ▶ Dedicated abandonment business team leads that have a strong voice and access to senior management.
- ▶ Willingness to change the status quo and to apply continual business improvement practices that are common to other parts of the upstream oil and gas industry and other businesses.

There is a perception that small Canadian E&P companies are dodging their responsibility for wellbore leakage and abandonments. This perception is enhanced by the recent news of bankrupt smaller E&P companies and the media attention applied to the ballooning count of orphan wells. The number of orphan wells greatly increased following the oil price crash that began in late 2014 as all companies in the oil industry struggled to stay profitable.

Smaller companies can be leaders in the abandonment and wellbore integrity field. As the saying goes, necessity is the mother of invention. When balance sheets were impacted with more realistic liabilities for abandonments, smaller companies had to become much more innovative.

Smaller companies that have had innovators on abandonment teams have been very successful in reducing their company's liabilities. These innovators have worked with other companies, suppliers, as well as industry organizations such as the WIA society and PTAC to create efficient and successful abandonment campaigns. An excellent example is listed in the main Best Practices report.

8.2 Relationship Between Industry Knowledge, Best Practices and Regulations

Industry knowledge is primarily developed by both E&P companies and service/technology companies. Experimentation on new processes and technologies becomes industry knowledge with time. The challenge with industry knowledge is ensuring the experimentation is properly understood, documented and verified. Future success hinges on understanding what has been previously accomplished. An analogy for industry knowledge is Alpha Testing in the software design industry.

Best practices are formalized documents that provide guidance to the industry. Best practices have general acceptance from the industry as they are formulated from industry knowledge. These practices can evolve and adapt as additional research/data becomes available. An analogy for best practices is Beta Testing in the software design industry.

In the past as regulations were initially developed, there was a strong reliance upon industry knowledge. Today, most of the industry has some form of regulation for each stage of the well life cycle. To create new or update existing regulations using industry knowledge alone is not possible due to the societal pressures that include the public's and non-governmental organizations' (NGO) concern regarding the industry's social license to operate. Industry knowledge is not enough to provide an adequate reason or sufficient evidence to change regulations.

The inclusion of industry knowledge in best practice documentation allows feedback from industry stakeholders and ensures proper science and experimentation has occurred. Best practices are a way to implement processes and, in some cases, technology that is superior to the mandatory regulations. To continue with the software design industry analogy, we move from Alpha Testing to Beta Testing.

Once best practices are formally documented, the documentation should be used to update the regulations to meet the current needs of industry and society.

8.3 Industry Knowledge

Industry knowledge is developed by both E&P companies and service/technology companies. This information is passed through E&P company mentorship or from service/technology companies looking to implement their processes and/or technology improvements for the E&P companies.

8.3.1 Industry knowledge concerns

- ▶ **Lack of knowledge sharing:** Remediation and abandonment teams rarely take time to formally share knowledge such as presentations and papers at industry events. This knowledge is commonly kept in-house, is often not formally documented, and is passed by word of mouth from mentor to mentee.
- ▶ **Lack of scientific rigour:** The biggest issue with industry knowledge is the lack of a disciplined scientific process to validate the results of the trial and error experimentations. When success is perceived to occur, this success is not well understood. Additional experimentation then occurs at other companies trying to replicate the success. Duplication of this experimentation causes the wellbore leakage path to improvement to be inefficient. Rarely is the experimentation subjected to peer review, other than a short presentation at one of the technical societies. A critical part of the process of turning industry knowledge into a best practice is the validation of the trial and error experimentation that formed the industry knowledge.
- ▶ **Outdated industry knowledge:** Industry knowledge, due to the two points above, is not subject to continued review and improvement. This has resulted in the continued use and promotion of ineffective and outdated industry knowledge.

8.3.2 Recommendations to improve industry knowledge

Two key recommendations for sharing industry knowledge are additional collaboration during the creation process, and sharing the new information.

Facilitating collaboration to improve the creation of industry knowledge: Often the trial and error method of creating industry knowledge is self-contained in the E&P path or the service/technology company. Collaboration between E&P and service/technology companies would be a more efficient and cost-effective path to the common goal of reducing and repairing wellbore leakage. Recommendations to facilitate this are:

- ▶ Facilitation of multiple parties that are usually in competition with each other will require a distinct neutral third party to make the collaboration a success and keep the project on track.
- ▶ Collaboration must include E&P companies, service/technology companies and consultants. Exclusion of any party would both decrease the value of the collaboration and provide a barrier to adoption of the industry knowledge.

Improving the sharing of new industry knowledge: Once companies have success, new industry knowledge information should be shared via technical presentations, formal papers or word of mouth. By sharing this knowledge, it will allow for additional groups to build on initial successes as well as identify areas where initial successes do not apply. Formal papers will also be able to be peer reviewed. Recommendations to achieve this include:

- ▶ Technical knowledge sharing can occur at both internal E&P information sharing and at industry conferences or industry society meetings.
- ▶ The Canadian upstream oil and gas industry needs to increase the amount of formal papers through a recognized wellbore leakage entity, like the SPE, to share industry knowledge within the country and internationally.
- ▶ Companies may be hesitant to share knowledge because they are worried about increased scrutiny from the regulator. In order to improve knowledge sharing, it is recommended that regulators not use knowledge sharing as an opportunity to target specific companies, provided such companies conducted their activities as per regulations.
- ▶ In addition to protecting knowledge sharing, additional incentives for E&P companies on related topics that would reduce immediate cost while improving long-term efficiencies should be considered. These incentives should be constructed around activities related to wellbore leakage, such as abandonment timeliness, area-based closures or orphan well payments.

8.4 Best Practices

8.4.1 Best practices concerns

Wellbore leakage currently has little documentation on best practices for prevention and remediation. Most “considered” best practices are decades old. These old best practices are significantly outdated and should no longer be considered effective.

An example of outdated best practices is the common practice of running a noise/temperature log to acquire data on source identification. This practice originated from “The Structure and Interpretation of Noise from Flow Behind Cemented Casing” (McKinley et al., 1973) on noise logging and is considered to be the current standard by industry personnel that are not intimately involved in wellbore leakage.

The technology and process presented in the McKinley paper should be consider the absolute minimum data collection required. Most abandonment engineers using the methods in the McKinley paper have not fully understood this paper. The paper is based on wellbore leakage in California from the early 1970s. Only one of the example wells had confirmed cement to surface. Often wells of this vintage in California had only the bottom section of the well cemented. In addition, the example wells had very high flow leakage rates. These types of wells would be an anomaly in Canada with modern well construction. These outdated practices have been improperly handed down from mentor to mentee without consideration of changes in industry, including the evolution of combining technology with process.

In addition to outdated practices, the creation of best practices takes significant time and resources. The author has seen IRPs with timelines of more than four years from initiation to completion and significant time investment. Who should be responsible for managing the cost of the best practices process?

The creation of new best practices on wellbore leakage must follow a standardized process that emphasises collaboration across stakeholders. The process of establishing best practices should utilize industry knowledge, technology development and science, as described in the following section.

Once best practices are crafted, they need to be communicated to the industry. Communication to industry needs to incorporate the reasons why the best practices should be followed. The best practices will often incur additional front-end costs; however, these costs will be offset by improved efficiencies and lower full life cycle well costs. The initial higher front-end costs will be a hurdle for some E&P companies, especially in the current low commodity price environment. The reasons for change must be clearly communicated to the industry to ensure the adoption of the new best practices.

8.4.2 Recommendations to improve best practice production processes

The first step in creating a best practice is defining which area will be addressed by it. With respect to wellbore leakage, there should be best practices (i.e. industry recommended practices) for drilling, cementing, completion, remediation and abandonment. For example, the recently released DACC IRP Volume #25, Primary Cementing (Drilling and Completions Committee, 2017) addresses primary cementation on new wells.

Preparation of a best practice will involve collaboration between E&P companies, service/technology companies, industry associations and regulators. A facilitator, such as DACC or CSA, will often be required to keep the project on track. Industry knowledge is amalgamated and vetted by the best practices steering committee. The best practices consortium decides which pieces of the process needs to be documented and where there should be flexibility in the process to incorporate future improvements.

In crafting a best practices process for wellbore leakage, stakeholders would include the following four distinct groups: industry, regulators, facilitators, and industry associations. Of the four stakeholders listed, E&P companies need to be major stakeholders as these companies have ownership of the wells. It is important, especially in the area of wellbore leakage, that E&P companies are not the only industry voice.

In the Canadian wellbore leakage space, service/technology companies are often the leaders in conducting R&D, resulting in technology improvements and pushing process boundaries for improvement.

Industry associations and societies must be consulted very early in the best practices process. The industry associations know which of their members have the highest knowledge of processes and technology.

8.5 Regulations

The majority of oil and gas activity is located within provincial boundaries and falls under the responsibility of the individual provinces. The provincial regulators are responsible to the people of the respective provinces who “own” the resources.

In 1938, Alberta’s regulator, the Petroleum and Natural Gas Conservation Board, was established to steward the province’s resources. This first regulator was to ensure that the oil and gas industry was held accountable to acceptable practices. Regulations were initially drafted from the available industry knowledge. Provincial regulations, in most situations, should be considered the minimum requirement for compliance.

Regulations are slow to change and will become outdated as the industry evolves. As an example, the first drilling and cementation regulation, established in 1938, did not consider that drilling would occur horizontally.

An area of concern, in addition to the need to evolve regulations, is that the regulations may differ between provinces—an issue for E&P companies with wells in more than one province.

8.5.1 Regulations summary

In summary, regulations need to be updated to the current needs of the industry to allow for efficient improvement of wellbore integrity. The updates to regulations should be validated by data gathered following the scientific process. This is different from industry best practices. Industry best practices can be the result of trial and error and may not have been validated by science.

The oil and gas industry is still in its infancy when conducting and documenting science on wellbore leakage. In addition, there is currently no process to present validated science to update regulations. This lack of a process to modernize the regulations through the use of science is a significant barrier to reducing wellbore leakage.

8.5.2 Recommendations for improving regulations

Regulations are difficult to change due to their nature. Historically there have been regulation changes that have caused unintended consequences and therefore regulators must consider the environmental impacts, industry economics, public perception and the sustainability of the resource. The modification and development of new regulations needs to be based on scientifically rigorous data.

The upstream oil and gas sector already participates in wellbore integrity science. However, industry perception is that there is limited interest and willingness on the part of regulators to consider modifying regulations based on such science (provided it was conducted in a scientifically rigorous manner).

In order to incent the industry to conduct and share the results of its wellbore integrity studies, regulators must develop a framework to evolve regulations as understanding of the wellbore integrity science is increased.

As an example, data have been supplied to a regulator demonstrating that the GHG emissions associated with repairing non-serious leaks on remote wells are significantly more than the wells would emit if left venting at ultra low rates. There is currently no provision in the regulations to consider this type of scenario, and thus all leaks have to be fixed regardless. In order to effectively reduce wellbore leakage-related emissions, it is recommended that leaky wells be prioritized so that the largest emitters are repaired first, and that repair-related emissions be considered to determine if remediating the well is even worthwhile.

8.6 Additional Recommendations to Reduce Wellbore Leakage

The previous three sections provided recommendations on reducing wellbore leakage by improving the development of industry knowledge, best practices/industry recommended practices, and regulations. The previous chapters of the TRM provided recommendations on reducing wellbore leakage during a specific phase of a well's life cycle. Below are a number of other recommendations that are more general in nature.

8.6.1 Communication of best practices

One of the largest issues in most industries is the process of disseminating industry knowledge and best practices efficiently. The upstream oil and gas industry in Canada should be considered as extremely conservative. There will be an internal resistance to change. Formal documentation of industry knowledge and incorporating this knowledge into a best practices document will greatly improve the acceptance of better practices.

As seen throughout the TRM, the current state of industry knowledge is quite extensive. There is, of course, additional knowledge to be gained, tested and validated, since every industry should strive for continuous improvement as has been highlighted in the TRM reports on drilling and completions, source identification, remediations, and abandonments.

A key recommendation to reduce wellbore leakage in the short and long term is to increase communication between stakeholders. Sharing of industry knowledge, followed closely by the creation of best practices, is the most efficient way to a quick win for both the industry and the environment.

8.6.2 Developing regulatory consistency amongst provinces

Provincial jurisdiction for the upstream oil and gas industry has the unintended consequence of regulations that can significantly differ between provinces. Varied provincial regulations make operating in multiple provinces less efficient for the industry when companies are required to follow different regulations.

In addition, the cost of adherence differs for E&P companies when regulations are different. This cost will impact the financial considerations of oil and gas development, providing an advantage to one province over another. This advantage may also coincide with a potential cost to the environmental impact of oil and gas development.

The western provinces are collaborating more often than ever before. The Western Regulator Forum was held on February 8 and 9, 2017. This forum included E&P companies, service/technology companies, NRCan, CSGM/WIA Society Executives, as well as regulator representation from Alberta, British Columbia, Saskatchewan and the National Energy Board (NEB).

The recommendation is to bring upstream oil and gas jurisdictions in Canada into close alignment with respect to regulations. Additional communication between regulators plus collaborative forums with stakeholders will create meaningful discussions on the best path forward for reducing wellbore leakage by aligning regulations.

8.6.3 Increase and fully utilize funding for research and development

Research and development is undertaken by academia, E&P companies, and service/technology companies. All three contribute to solving wellbore leakage issues in different ways. The TRM is to provide a current snapshot of the wellbore leakage in the upstream oil and gas industry. The hope is that a coordinated effort will make the additional changes necessary to efficiently solve the issues surrounding leaky wells.

Canada has numerous tax credits, grants and subsidies available; these are detailed in the full Best Practices report. While academia understands most funding options available to them, oil industry companies do not. Funding will be required from both the industry and governments to accomplish the TRM goals. In addition, as mentioned in the R&D section of the Best Practices report, there are additional avenues to provide funding which will assist the upstream oil and gas industry in reducing wellbore leakage.

Communication of R&D funding options is a recommendation. A related recommendation is to provide wellbore leakage-specific funding into a combined pool from federal, provincial, NSERC and industry sources with a long-term commitment (10 years+) that will enable the recommendations from the TRM to be fully realized. This funding pool should be handled by an independent party that has the ability to facilitate all stakeholders and coordinate the TRM R&D recommendations.

8.6.4 Full life cycle project analysis

In most industries, budgets are compartmentalized to provide a reasonable amount of autonomy to individual teams. The oil and gas industry is no different. The drilling and completions team's budget is kept separate from the production and abandonment budgets.

A consequence of separate budgets and incentives in siloed organizations is that teams are discouraged from considering the cost of the entire life cycle of wells in their planning and execution. When a well is not drilled or completed properly, there may be additional remediation and abandonment costs. These costs can be significant, especially if there is a surface casing vent flow on deep wells that have internal hardware. The author has personally worked on wells that have cost millions of dollars per repair attempt.

Raising awareness within the upstream oil and gas industry of the high cost of well integrity failure is a recommendation of this report.

8.6.5 New employee training and education

An additional suggestion for reducing wellbore leakage is to have new technical oil and gas employees exposed to the industry in reverse, rather than the current practice of starting at the beginning of the well life cycle in the drilling department. Starting a new engineer in training (EIT) in the abandonment department prior to moving to other areas of the oil and gas business gives the new employee a unique perspective on how all of the other phases of the well life cycle impact abandonments. The drilling and completion phases are the two biggest expenditures of an oil and gas well and have the most impact on the cost of abandonments. Wells that are poorly drilled or completed will cost orders of magnitude greater to abandon.

8.6.6 Multi-well abandonment programs

Another key component of efficient abandonment campaigns is the ability to treat the campaign as a multi-well project instead of individual wells. The author has seen good multi-well campaigns from both large and small operators as well as the exact opposite results for both company sizes. Larger companies have more abandonments and therefore it should be easier for them to have bigger multi-well abandonments. Having more abandonments does not mean that a multi-well program is well executed.

A recommendation for improving abandonment efficiencies is to provide the abandonment team, whether it is composed of consultants or an internal team, a significant role or voice in the long-term viability of the company. Too often, companies prioritize drilling and completion of new wells when they also need to understand the cost of managing their assets to end of life.

8.6.7 Dedicated abandonment teams versus part-time employees and consultants

To be effective, E&P companies need to have personnel dedicated to abandonments. At smaller and intermediate companies, this dedication does not need to be a full-time employee with 100% of their time dedicated to abandonments; however, the personnel must have a primary focus on reducing wellbore leakage and abandonments. There is specific technical knowledge with respect to wellbore leakage repair at time of abandonment. Dedicated personnel will be able to learn and develop this knowledge to continually improve the process.

8.6.8 Long-term abandonment planning versus short-term compliance

Successful abandonment projects require adequate funding and significant detailed planning. There needs to be a long-term plan (5 years +) to ensure efficiency. Regulators need to shift their thinking to offer more flexibility to allow E&P companies, especially larger companies, to efficiently manage long-term abandonment projects. However, E&P companies must be held accountable to their long-term plans on a yearly or even better, on a biannual basis. Long-term plans must have adequate funding, regardless of commodity pricing.



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