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Plug and abandonment practices and trends: A British Columbia perspective

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ABSTRACT

We present a review of plug and abandonment (P&A) practices in onshore wells, with a particular focus on British Columbia (BC). Regulatory and operational practices are reviewed as well as data on the wells of BC. This data set (of approximately 25,000 wells) has wider significance as it consists most recently of pad-drilled unconventional gas wells, with significant horizontal extent, multi-stage fractured. The oldest of these wells and other vertical/deviated well stock are currently being abandoned. The data reveals a large wave of abandonments coming in the next decade and a significant increase in reported SCVF over the past decade, which will lead to rising P&A costs.

1. Introduction

British Columbia (BC) has long been an oil and gas producer with the earliest reported well drilled in 1919. Over 25,000 wells have since been drilled in the province, more than 14,000 of which were drilled since 2000. Although BC has some $16.5 \times 10^6\,m^3$ (103.7 MMSTB) of oil, wells in the province mainly produce gas from unconventional resources. As of 2016, 85% of the produced gas was from these resources. According to recent estimates, recoverable gas reserves in BC are $1485.4 \times 10^9\,m^3$; see BCOGC (2016a). Currently, the two main productive areas in BC are the Montney and the Horne River basin; see Fig. 1. As with many areas of North America unconventional gas is produced from shale predominantly using multi-stage hydraulic fracturing as the recovery method. Recent wells are largely horizontal pad drilled monobores. These shifts in practice since the early 2000's largely account for the recent increases in production. Cumulative production from the Montney surpassed 4.3 trillion cubic feet in December 2015, (NRC, 2017).

In this paper we review the BC industry from the perspective of plug and abandonment (P&A), in terms of the well stock, regulatory and current practice. Such a review is timely since, as the statistics show, the number of wells that will be due for abandonment in the next decade is similar to the number that have been abandoned in BC since the start of the industry. Thus, it is time to critically review regulations and practices.

Industrial interest in operational, technological and regulatory aspects of P&A is currently high and likely to continue to grow in the coming decades. Western Canada, has seen a heightened public interest in well abandonments over the past 2 decades, including a number of damaging news reports. Such scrutiny can be helpful to the industry in motivating continued attention on what might otherwise be viewed purely as a cost item. However, news reports rarely consider the technical difficulties and operational constraints, which it is our intent to review here. Also often ignored is the generally constructive response of industry stakeholders in Western Canada, in being self critical and looking to improve their own practices, e.g. as with NRC (2019), continual updating of best practices recommendations, etc.. Our review is intended to lend a different perspective to this process.

The broader relevance of the BC dataset is threefold. First, BC has had a significant number of conventional wells as well as the recent unconventional boom, within an experienced industry dating back over 60 years. This lends relevance in terms of neighbouring Alberta, with 20 times the number of wells, a wider diversity of well types and geology. Secondly, BC is relevant to many of the land-based unconventional gas plays that have emerged globally in the past 10–15 years. These have similar wells and completion methods, and are also now experiencing P&A operations on the first of these developments. BC wells are not HPHT, nor exceptionally long/deep, nor otherwise exceptionally difficult. Their relative ordinariness makes them relevant globally. Thirdly, BC has a open democratic governance and strong public environmental lobby. The regulatory environment in BC is consequently open and transparent with public access to industry data and good recording practices.

The increasing numbers of P&A wells in BC is not an isolated phenomena. The recent review (Vrålstad et al., 2019a) talks of a “P&A wave”. This is arising naturally due to maturity of established areas, but

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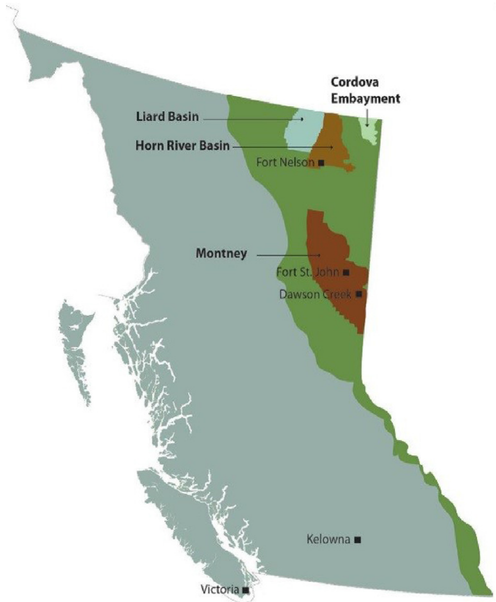

Fig. 1. Unconventional gas play trends in northeast British Columbia NRC (2017).

also reflects reduced lifetimes of newer horizontal wells and of some unconventional well types. Thus, P&A has been of growing interest and previous knowledge is in need of updating (Calvert and Smith, 1994; Barclay et al., 2001). The recent Vrålstad et al. (2019a) gives an excellent overview of P&A in offshore environments, with a North Sea focus. Onshore abandonments benefit from easier access to wellsites and significantly lower costs, but share objectives of longevity of the sealing operations and use broadly similar techniques. Here we review not only operational features but also the underlying regulatory aspects. As shown by Van der Kuip et al. (2011) there is a broad range of regulations worldwide, even in geologically similar situations. There is less clear direction on why a given regulatory requirement is deemed adequate to seal a well, i.e. from a physical or mechanical perspective: questions that should be subjected to scientific scrutiny and promote research. Equally, well leakage and environmental damage does not respect jurisdictional boundaries.

Onshore abandonments are strongly linked with well leakage, either gas migration (GM) or surface casing vent flows (SCVF), for which there are a number of studies focused at Western Canada. In some cases strong local variations in leakage rates are reported, e.g. Dusterhoft et al. (2002). Mechanical causes of leakage are reviewed by Dusseault et al. (2000). In Watson and Bachu (2009) the authors review regulatory and operational aspects of abandonments and leakage in Alberta, with the focus on CO_2 storage. A wider Canadian perspective is given by Dusseault et al. (2014), comparing between provinces and discussing possible improvements, but focusing mainly on leakage during production. The recent NRC (2019) presents a technology roadmap towards improvement.

The aim of our paper is to take data from one Canadian province (BC) and analyse in depth to understand the trends. We do this both in the regulatory context and by considering well operations. In §2 we start by examining the goals of a P&A operation, which is not apparent. Section 3 considers trends in well construction in BC and how these affect abandonment. In §4 we review the data on leakage in BC. Regulated abandonment methods are considered in §5 and in §6 we survey which P&A options are most prevalent. Section §7 looks at aspects of well preparation and plug placement operations. Finally we address longer term issues related to usage of cement and how leakage pathways develop (§8). This latter part of the review is more generally applicable than only to BC. The paper ends with a summary and discussion of our findings and recommendations.

2. Goals of P&A operations

What are the end goals of a P&A operation? There are different opinions and this is an important debate that is often overlooked. Oil & Gas UK has described the aim of P&A as “restoring the cap rock” (see Fig. 1 in Oil and Gas UK (2015)). The Norwegian sector of the North Sea is governed by NORSOK (2013), wherein it states “Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented.”; (see §9.6.2). In Western Canada, both Alberta and BC follow AER (2018), in which it is stated: “The objective of a well abandonment is to cover all non-saline groundwater and to isolate or cover all porous zones.”.

These differing opinions contribute to divergence in actual regulated practice, as is nicely summed up in Van der Kuip et al. (2011). Since jurisdictional and geological boundaries do not generally align, we can have e.g. a plug set in geologically similar wells in the North Sea with length either 30 m or 100 m, depending on UK or Norwegian jurisdiction. There is also consistency between these sectors: both have adopted a similar 2-barrier system, i.e. there is always a secondary barrier to leakage. The key building block of all North Sea P&A designs is the idea of a well barrier, which is an “envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, another formation or to the external environment”, NORSOK (2013). Each barrier is made up of a number of connected well barrier elements, which prevent flow across them individually. Each interval to be abandoned requires a minimum of 2 well barriers, in both horizontal and vertical directions. These are determined at the design stage and drawn explicitly for each well schematic. Primary and secondary well barriers cannot share the same elements, so that each barrier is independently able to prevent flow to surface or into another permeable zone.

Canadian P&A designs do not follow a 2-barrier concept, although many designs result in multiple barriers. Instead they focus on isolating porous zones and on groundwater protection. There are also differences in the type of operations commonly used, e.g. it is uncommon to mill and pull a casing. A significant reason for the difference here is that the North Sea wells are offshore: extreme cost and difficulty of re-entry are drivers for the more stringent North Sea requirements, i.e. permanent should be permanent.

Onshore Canada has harsh weather but even remote well sites are accessible if needed. Although ideally we would like to see multiple permanent barriers placed in each well, it is equally important that abandoned wells are monitored/tested for leakage at regular intervals. We do not know the actual lifetimes for all materials that are used, often in non-ideal downhole settings, nor which element of a barrier is most likely to be compromised. Permanence of e.g. cement is also illusory compared to geological timescales of caprock, although material timescales may be long relative to the lifetime of a company (perhaps of the industry as a whole). Thus, the eternal perspective is sadly at best a helpful ideal.

A completely different industry model that could be considered in accessible land regions is that of non-permanent sealing and continual monitoring. Bridge plugs (BPs) are relatively easy to place and replace. Could industry protocols and regulations be developed for continual servicing and replacement of BPs, coupled to squeeze/remediation for SCVF and open hole sections? Would this be better or worse, from a public/environmental perspective, now and in the future? We have no specific advocacy here. The point is that regulatory frameworks and standards lie on a broad spectrum of possibilities. It is important not to brush off other possible models. As with other industries with waste/remediation/restoration issues, oil & gas faces environmental management questions that are sufficiently long-term to be considered both post-career and potentially post-industry, i.e. we need to regulate now for that uncertain future.

Aside from a stated end goal, regulatory frameworks and their implementation are influenced by at least 3 factors. (a) Legal responsibility: regulations do not advise best practice, as to do so would assume some liability in the event of failure, i.e. in most jurisdictions liability stays with the owner of the well. (b) Public and environmental interest: wherever the regulatory body is a branch of a representative and responsible government, as in BC. Regulated industries cost tax money. (c) Engineering practicality and cost: is it better to have idealistic goals or pragmatic ones that are consistently executed and may be progressively improved?

Lastly, above we have questioned abandonment goals in terms of what is being protected and for how long. A different and more technical question concerns whether we aim to seal *completely*, or to control a leakage rate and/or withstand a pressure threshold? Are these goals dependent on the reservoir fluids? If the objective is to "restore the cap rock", then the cap rock has been penetrated in depleted heavy oil reservoirs and even in "dry holes", neither of which have a driving mechanism for leakage/contamination of groundwater. This consideration is relevant to how we measure success or failure of the plugged well, i.e. don't include in statistics of leakage those wells that anyway have nothing to drive leakage.

3. Wells of BC

The type of well being abandoned has significant impact on plug and abandonment operations performed. Activity levels in BC stayed fairly consistent from the 1960s to the beginning of the 1990s. During the later part of this decade and the early 2000s there was a huge increase in drilling and production in the BC, as illustrated in Fig. 2, showing the number of new wells drilled annually. A significant shift can be observed from drilling mainly vertical wells to a majority of new wells being horizontal, around 2005. Horizontal wells constitute over 95% of the new wells drilled over the past 5 years. The well database used for this study includes 24,421 wells, 14,298 of which are vertical, 7202 are horizontal and 2921 are directional/deviated.[1]. Of this data set, 40.5% of the wells are currently active, 30.3% are abandoned and 21.2% are suspended. The remaining 8.0% are at some initial stage of completion. Test hole wells, wells at the licensing stage and gas testing wells were removed from the status analysis.

3.1. Abandonment data trends

We now look in more detail at those already abandoned and those to be abandoned in the coming decade. According to data published by the British Columbia Oil and Gas Commission (BCOGC, 2016b), as of December 2016, 64% of the abandoned wells in the province had been restored to meet regulatory requirements. Of the wells which are classified as abandoned in the database, about 56% have been abandoned within one year of being drilled. These wells were most likely a dry hole. Procedures for abandonment differ according to well type (see §5 later) and leakage risk from a dry hole is reduced.

With advances in seismic technology and the move towards pad drilling of multiple horizontal wells and more effective stimulation methods, the number of wells being abandoned immediately after drilling has gone down significantly over the past decade with only 61 wells being abandoned within 1 year of drilling, as compared to 730 wells for the previous decade; see Fig. 3. This trend is likely to continue, so that future abandonments will be increasingly production wells with higher potential to leak.

Disregarding wells abandoned within one year, as they are not a representative example of wells being put into production, the average age of a producing well at the time of abandonment in British Columbia is 17.3 years. Here we measure age from the rig release date and the lifespan is taken up until the date of abandonment. Other definitions are possible, each with different advantages and limitations. This can be further broken down depending on the type of well: for horizontal wells the average age at the time of abandonment is 9.6 years, 12.1 years for directional/deviated wells and 18.3 years for vertical wells. Note that the sample size for horizontal wells is much smaller than it is for vertical wells, as relatively few horizontal wells have been abandoned in BC to date. A shorter lifespan is expected for horizontal wells as they intersect a larger section of the reservoir compared to vertical wells and therefore should deplete at a faster rate. On the other hand, the lifespan includes time suspended, which is longer for the older vertical wells, on average.

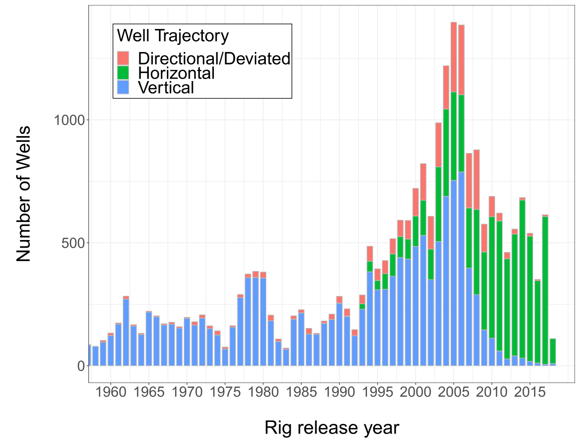

Fig. 2. Wells drilled each year in British Columbia.

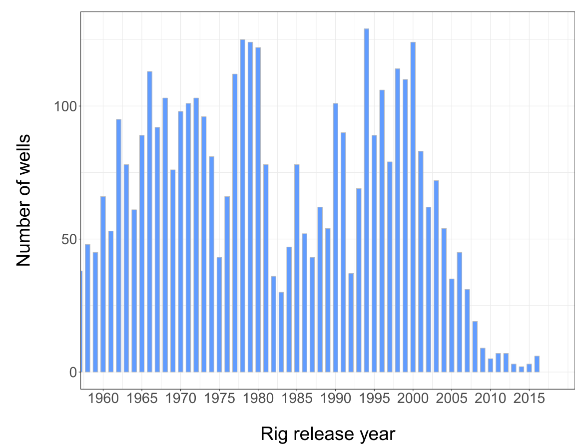

Fig. 3. Number of wells abandoned within one year of drilling.

Fig. 4 shows the age of wells in BC, according to their trajectory. The average age of active or suspended wells in BC is currently 9.27 years for horizontal, 16.68 years for directional/deviated wells and 25.73 years for vertical wells. Examining the data more closely, there are 4097 vertical wells older than the average lifespan of 18.3 years. Similarly, there are 1368 directional wells older than the average lifespan and 2792 horizontal wells older than the average lifespan. In other words, there are currently ≥ 8200 wells in BC that are older than their average lifetime.

At the moment, 21.2% of the wells in the database are suspended. A well is considered suspended after 12 consecutive months of inactivity, or 6 months in the case of special sour or acid gas wells. Requirements for suspended wells vary depending on the length of time the well has been suspended and the nature of the well (BCOGC, 2019b). In BC, a

[1] https://www.bcogc.ca/online-services, accessed November 2018.

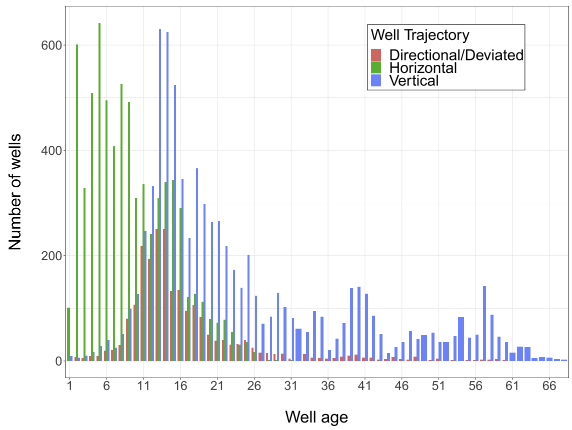

Fig. 4. Age of wells in British Columbia based on the well trajectory.

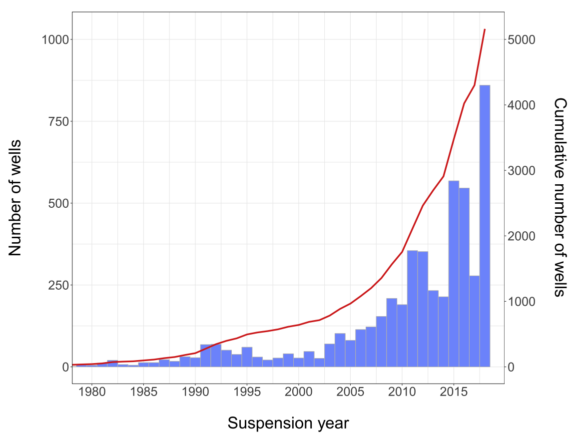

Fig. 5. Current number of suspended wells in British Columbia based on suspension year and cumulative numbers (solid line).

well that was suspended will remain in this state for an average of 8.26 years. Currently 573 wells have been suspended for over 20 years. Fig. 5 illustrates the growing stock of suspended wells in BC. The total number of wells in a suspended state at any given time has been growing over the past 2 decades, shows no sign of slowing down or levelling out. Fig. 5 reflects both industry practice and the regulatory environment of the past years, some of which allows relaxed timelines on lower risk wells.

In summary, we see that the trend is towards less dry holes, shorter lifespan wells (horizontal) and increasing numbers of suspended wells. There is currently no incentive for an operator to abandon a suspended well. Over 8200 wells are above their average lifespan and could be considered as being due for abandonment. This figure is comparable to the total number of wells that the industry has abandoned in BC over the past 80 years. It is clear that there is a significant wave of abandonments coming to BC in the next decade.

3.2. Well type

The overwhelming majority of the ≈ 25,000 wells in BC are gas wells. Only 9.7% of the wells in the province are oil wells. Pressure data was available for 14,467 wells and temperature data for 13,156 wells. Based on the API criteria for high pressure and high temperature (HPHT) wells, (a shut in pressure greater than 103 MPa (15,000 psi) or a flowing temperature at surface greater than 350 F; see API (2018)), only 1 well in BC has a higher pressure and only 2 wells have greater flowing temperature. Even based on less stringent definitions set forth by Schlumberger, (a shut in pressure greater than 69 MPa (10,000 psi) or a temperature greater than 302 F, see Smithson (2016)), only 26 wells in BC would be classified as HPHT. Thus HPHT wells are not a specific concern in BC.

Other concerns for operators are whether hydrogen sulfide (H_2S) or carbon dioxide (CO_2) are present in the well, due to safety and corrosion concerns, respectively. A database of 12,646 wells includes gas analysis. According to this, 17.3% have a CO_2 fraction of 5% or more and 37.5%, have recorded the presence of H_2S. According to BCOGC, any well with a measurable amount of H_2S concentration is considered a sour gas well. A well is classified as special sour gas based on its closeness to an urban center and its release rate. Directive 020 (AER, 2018) classifies a well as a Level A interval if the H_2S concentration is greater than 15%, these wells are subjected to stricter abandonment requirements. Based on the gas analysis database discussed here, 199 wells or 1.6% of the wells in the gas analysis database would have a Level A classification. A further 4.9% of the wells in this database have a H_2S fraction between 5 and 15%.

3.3. Well architecture

Around 32% of the wells in the database have a measured depth (MD) of 1000 − 1500 m. The average MD is 2125 m and the median is 1720 m. The MD has been increasing in recent years (see Fig. 6), associated with the increased number of horizontal wells. Horizontal wells, which are representative of the new wells being drilled and put into production in BC, have an average MD of 3443 m (median 3638 m), and an average true vertical depth (TVD) of 1670 m (median 1968m).

A majority of wells in the database, 74.1%, have 2 casings followed by 15% of wells with 1 casing. The remainder have 3 or more casings. Note that conductor casings are not considered for the purpose of this analysis. Before 2000, 93.1% of wells drilled had only 1 or 2 casings, since then, the use of a third casing has increased to 13.7% for all new wells drilled, see Fig. 7. The use of only 1 casing, the surface casing, has also decreased from 31% before 2000 to 3.8% of wells drilled from 2000 onwards. Wells with 1 casing will be either dry holes or open-hole completions. The type of wells does not significantly affect the number of casings in a well: 72.3% of vertical or deviated wells and 79.2% of horizontal well have 1 or 2 casings.

For a snapshot of current well construction, we sampled 31 wells with a rig release date in 2010 or later and analysed the drilling reports more closely. For each of the top 5 operators currently operating in BC, 5 wells were selected and an additional 6 wells belonging to smaller operators were added to the list. All wells were selected randomly. The selection resulted in all gas wells: 27 horizontal, 4 directional.

All but 5 wells only had 2 casings, a surface and production casing. The measured depths of the wells range from 1580 m to 5745 m with a

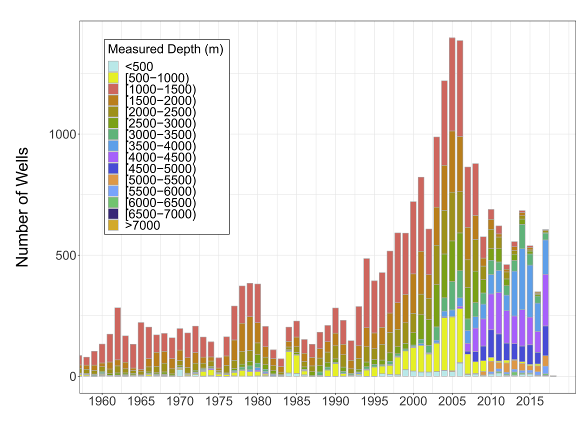

Fig. 6. Measured depth of wells in British Columbia based on rig release year.

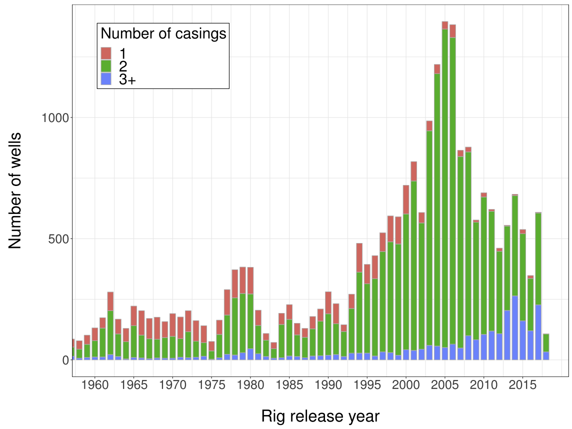

Fig. 7. Number of casing in wells based on rig release year.

median of 4000 m, which is representative of current wells. Surface casings were cemented over their full length and cement return at surface were confirmed for all. For all production casings cemented to surface, returns at surface were confirmed. Only 2 wells did not have their production casing cemented to surface. Only 3 of the 27 horizontal wells did not have a casing extending in the horizontal section, some extended partially and 15 from 27 (55%) were cemented to full length. Additionally, all wells with the exception of 1 directional well were cemented in 1 operation. We conclude that current wells are generally cemented to surface, the majority are cased hole completions and staged cementing is uncommon in BC.

The above statistics are presented mainly to give an idea of the BC environment. In BCOGC (2017) are given estimates of liability (in terms of 2017 abandonment and reclamation costs) for different well types and this varies with depth, for example. In practice the abandonment cost depends on number of plugs set (dependent on the number of completed zones) and particularly on the need for remedial work; see §4 below.

3.4. Hydraulic fracturing

Hydraulic fracturing (fracking), has been reported as early as 1950 in the province. In BC, use of hydraulic fracturing jumped from 19.8% of wells in 2004 to 54.6% of wells in 2005 and has remained very high since then; see Fig. 8. There are approximately 5000 wells for which the data is missing, largely dating from pre-2004. While the use of hydraulic fracturing slightly precedes the rise in horizontal wells, both have become much more common during the drilling boom of the mid-2000s. As a result, 59.3% or 4270 out of 7202 horizontal wells are hydraulically fractured. Considering wells after 2010, this has jumped to 84.8% of new horizontal wells. Mostly these are fractured in multiple stages, with >50 stages being common in recent years.

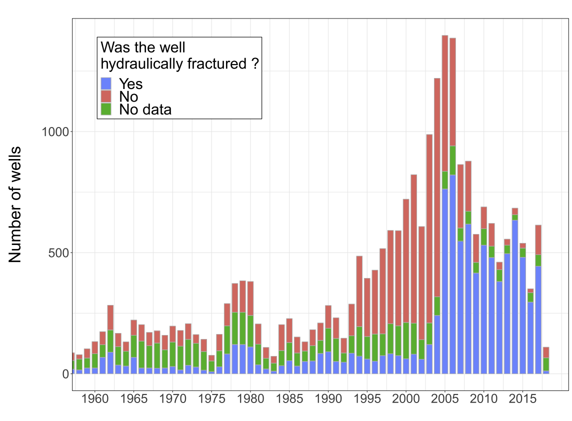

Fig. 8. Use of hydraulic fracturing based on rig release year.

4. SCVF/GM

Surface casing vent flow (SCVF) and gas migration (GM) are two types of fluid leakage which may affect wells at any time through its lifecycle. SCVF is defined as the flow of fluid from the surface casing vent assembly. GM is defined as fluid flowing outside of the surface casing of a well. In the P&A context, both compromise the aims of AER (2018): to isolate porous zones and cover non-saline groundwater. Additionally, SCVF and GM represent environmental and safety hazards.

GM testing is only required if there is any indication (visual/auditory/olfactory) of gas migration or if there are any issues noted during drilling, completion or with the well condition that could indicate the potential for GM. If GM is discovered around a well, the operator must notify the regulator within 72 h. A risk assessment, including proposed mitigation and management measures, must then be submitted to the regulator within 90 days. Thus, GM issues are dealt with quickly and are not considered particularly relevant in the context of P&A (BCOGC, 2019b).

In contrast, SCVF testing is conducted on at least 5 different occasions: after initial completion or re-completion, at the time of rig release, during routine maintenance, before well suspension and finally at the time of abandonment. The SCVF is characterized as serious if it has a flow rate greater than 300 m^3/day, if hydrogen sulfide (H_2S) is present, if oil (liquid) is present, if the stabilized shut in pressure is greater than half of the formation leak off pressure, if the vent flow is caused by casing or wellhead seal failure, if the vent flow poses a threat to groundwater or if the vent flow presents a fire, public safety or environmental hazard. All other vent flows are deemed non-serious.

While many SCVF testing methods exist, the minimum accepted test in BC is the bubble test. The bubble test must be at least 10 min in duration and consists of a small hose or pipe fitting connected to the surface casing vent assembly, directed to a water container and immersed a maximum of 2.5 cm below the water surface. Any gas flow, i.e. bubbles, must be recorded as a positive vent flow. The flow rate and stabilized buildup pressure must be determined and reported to the regulator; see chapter 9, section 9.7.3 of BCOGC (2019b).

Severity of the vent flow determines the course of action available to the operator. In BC the repair of non-serious SCVF can be delayed until the time of abandonment and this is often the case. From a pure cost perspective, abandoning wells with SCVF can be significantly more expensive due to additional remedial operations. The remediation cost is still borne by the operator and beyond immediacy of cost and other internal organizational factors, it is unclear the advantage to the operator of delaying repair.

As an indication of P&A costs, wells without known leakage issues can be abandoned for anywhere from around $50,000 upwards, as recent examples indicate. On the other hand, in 2012, a vertical well with SCVF and GM issues was abandoned and remedial cementing was performed at the time of abandonment. The cost of abandonment for this well, excluding the cost of cut and cap, was over $1.9 million, a 10–40 fold increase in cost over the wells with no SCVF and GM. Other indications come from BCOGC's (2017) liability management rating (LMR) tables in BCOGC (2017), which indicate $50,000-$150,000 for abandonment and $30,000-$130,000 for reclamation. With an additional $62,400-$87,200 for wells with SCVF/GM and additional amounts for additional completed intervals.

Thus, a key motivation for dealing with SCVF/GM is cost. While it makes sense to fix such problems soon, thus benefitting from better production rates throughout the lifetime of the well, the end-of-life costs might not be borne by the same division of the operator so the incentive is not there. Hopefully as more industries adopt the practice

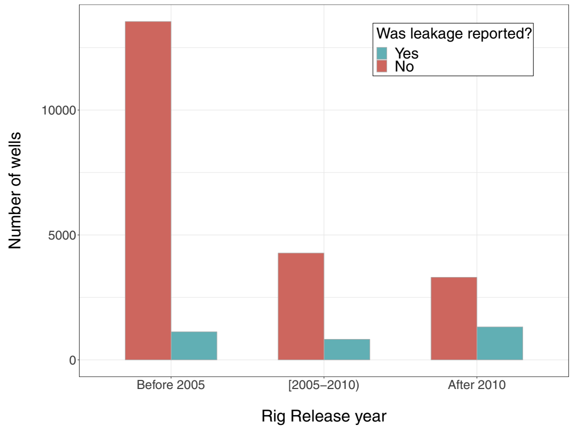

Fig. 9. Reports of SCVF for wells drilled before 2005, from 2005 to 2009 inclusive and from 2010 until 2018.

of budgeting for end-of-life costs (demolition, recycling, remediation …), the oil & gas industry will be able to reorganize so that P&A divisions will be able to influence practices for well construction and integrity, that later deliver rewards in terms of P&A cost-reductions. .

4.1. SCVF occurrence

As of 2018, 13.9% of all wells in the province have reported an instance of SCVF. This figure is in the range reported by Dusseault et al. (2014), but refers to all wells drilled historically. Changes in both regulation and self-reporting occurred in 2010. Focusing only on wells drilled from 2010 to 2018, we find that 28.5% of wells report SCVF. It is important to note that operators which had drilled and/or abandoned wells prior to 2010 had no obligations to return to and retest their wells for SCVF. For this reason, the percentage of wells having reported leakage since 2010 is considered a more accurate representation of actual SCVF rates.

Fig. 9 further breaks down the reports of SCVF for wells drilled from 2005 to 2009. These wells represent the beginning of the transition from a well stock consisting mostly of non-fracked vertical wells to a well stock of fracked horizontal wells, which represents today's activity. For 2005–2009, the percentage of well having reported SCVF is 16.2%. While wells drilled prior to 2005 have a much lower reported SCVF percentage at only 7.7%. This suggests that the transition to horizontal fracked wells accounts for an increase of around 8.5% and the shift to self-reporting resulted in an increase of 12.3% in reported SCVF.

In terms of causality, we note that 88.9% of the wells drilled after 2010 are horizontal and also 84.8% of these horizontal wells have been hydraulically fractured. It is difficult to distinguish between these two factors as potential causes of the increase in SCVF. Some insight is gained by focusing on the period from 2005 to 2009. During this period, 31% of the wells drilled were horizontal and 61% of the wells drilled were hydraulically fractured. The percentage of horizontal wells drilled during this period which have reported SCVF is 23.6% and 44.7% of these leaking well are hydraulically fractured. If focusing only on hydraulically fractured wells drilled during this time period, regardless of trajectory, the percentage of wells having reported SCVF is 16%. This indicates that horizontal are more likely to leak regardless of whether they were hydraulically fractured or not. Of course this also does not rule out an influence of hydraulic fracturing on horizontally cemented zones.

Horizontal well cementing is more challenging, due to a number of factors, e.g. slurry stability, poor eccentricity, incomplete displacements, etc. Since most BC wells are cemented over the full length it may be possible that poor cementing of the horizontal section affects the vertical part of the production casing too, allowing leakage above the caprock. Presumably then gas propagates along the cement formation interface and to surface within the surface casing, as the easiest pathway. In terms of hydraulic fracturing, multi-stage fracturing is common in BC, e.g. in 2013 an average of 18 stages were reported in the Horn river basin (BCOGC, 2014), but currently it is common to use 50 or more stages in BC. This repeated pressurizing compromises cementing, e.g. via debonding from the wall and/or radial cracking, as in Watson et al. (2002); Vrålstad et al. (2019b). Combined with other difficulties, the large number of frac stages and consequent damage, means that the sealing ability of horizontal sections is often compromised. Various studies of the effects of pressure cycling on the cement sheath have revealed radial cracking, e.g. .

Others have also pointed out a correlation between increased SCVF and unconventional gas wells, e.g. Ingraffea et al. (2014) which focuses on Pennsylvania. However, while there are many studies of wellbore mechanics and of (hydraulic) fracturing mechanics, we don't know of any study that has clearly delineated the mechanical effects of fracturing on the cement.

The data on SCVF also contains information concerning the severity of the vent flow, test type, flow substance, gas flow rate, whether H_2S was present and the stabilized shut-in pressure (van Besouw, 2018). Some information is however missing. Therefore, the total number given in each statistic below may vary from the total number of reports and wells in the database. The database of SCVF report contains 8227 entries representing 3391 wells. A given well can have multiple entries associated with it representing different tests. Information concerning the severity of the SCVF is available for 4657 wells, of which 75%, were for non-serious SCVF, 6.1% were for serious SCVF and 18.9%, reported no emission. In the case of the entries with no emission, the well was confirmed to have leaked at a different time and the entry was kept in the database.

Information about the fluid is given for 7201 of the entries in the database. Of these entries, in 89.5% of the cases, gas was the reported fluid. Liquid hydrocarbons were reported only 71 times. Information concerning the presence of H_2S is in the database for 3822 entries with only 55 cases of SCVF with H_2S reported. Note that serious SCVF cases reported must be repaired immediately.

Data concerning the gas flow rate is available for 5132 of the entries and is presented in Fig. 10. Data for which the gas flow rate was reported as 0 m^3/day has been removed from this figure, resulting in 4061 data points. The average gas flow rate for the non-zero gas flow rate reports in this figure is 24.56 m^3/day. The overwhelming majority, 86%, of the non-zero gas flow rate reported here are below 10 m^3/day. The median is around 1 m^3/day.

The stabilized build-up pressure was reported for 5251 entries, with 200 of these reports being for pressure of 0 MPa. The average reported stabilized build-up pressure was 5.16 MPa: 37.1% of the entries with non-zero values for build-up pressure were below 1 MPa and 25.6% of

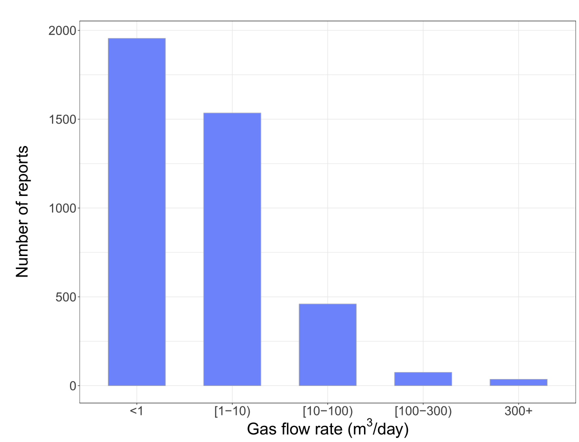

Fig. 10. Gas flow rate for wells with reported SCVF.

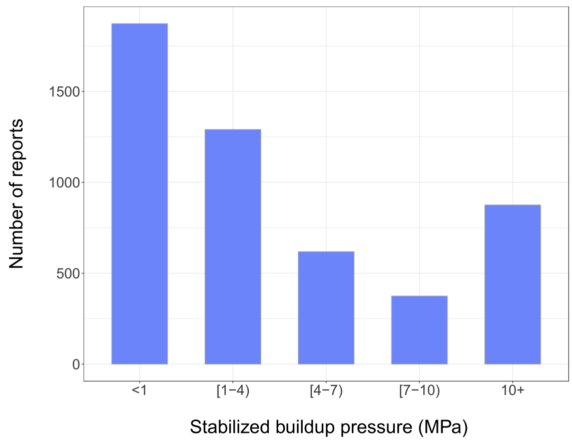

Fig. 11. Buildup pressure for wells with reported SCVF.

the entries had a reported stabilized build-up pressure between 1 and 4 MPa, as shown in Fig. 11.

The stabilized build-up pressure was reported for 5251 entries, with 217 of these reports being for pressure of 0 psi. The average reported stabilized build-up pressure was 780.6 psi: 31.2% of the entries with values for build-up pressure were below 100 psi and 28.5% of the non-zero entries had a reported stabilized build-up pressure between 100 and 500 psi, as shown in Fig. 11.

There are some rare extreme cases. The maximum reported value for gas flow rate was 17,300 m^3/day which is more than 57 times greater than the threshold for a serious SCVF. Whether such a flow should be classified as SCVF or a complete casing failure, i.e. well control incident, is debatable. The same well was reported having a non-serious SCVF 9 months later, at 100 m^3/day. Again at a later time the well had a serious SCVF of 15,000 m^3/day. The latest entry for this well shows no SCVF and the well was abandoned a few years after these serious SCVF were reported. The maximum reported shut in pressure was 66.32 MPa. This well was deemed a serious case of SCVF despite the gas flow rate being only 3.6 m^3/day.

We may use mean SCVF flow rates with the earlier well lifetime estimates in order to generate estimates of leakage per year for average wells and for BC as a whole. To do this we first calculate an average leakage rate for each well with any reported non-serious non-zero SCVF. We then average non-serious reported SCVF wells to find a mean leakage rate of 5.76 m^3/day which is 1.5 tonnes of CH_4 per year per well. Over an average lifetime of 16.1 years this gives 24.15 tonnes of methane per well. For 3391 wells with a reported SCVF incident at some time, this suggests that 81,893 tonnes of methane have been released from wells due to SCVF in BC. Since monitoring of wells post abandonment is not done in the province, there is no way to extend this calculation beyond the lifetime of the well.

Dusseault et al. calculated that, based on an estimated median flow rate of 0.5 m^3/day, a single well would emit 0.1 tonne of CH_4/year while using mean SCVF emissions resulted in 2 tonnes of CH_4, per year per well (Dusseault et al., 2014). Atherton et al. estimated that the active wells in the Montney emit 46,280 tonnes of CH_4 per year while abandoned wells in the same area emit 10,392 tonnes of CH_4/year; see Atherton et al. (2017). These estimates were made from mobile measurements performed in 2015. Some inconsistencies in Atherton et al. (2017) have been critiqued in govt. (2019).

Of course, making such estimates can over-estimate leakage rates since one needs to determine when SCVF was detected, make assumptions regarding the flow rate, correct for periods of well suspension, etc. Nevertheless, given that much of the leakage concerns CH_4, which has a global warming potential of 28–36 times worse than CO_2 over 100 years, the GHG contribution should not be ignored.

Table 1
SCVF rates for top 5 operators in BC, by number of horizontal gas wells drilled from 2010 to 2018.

Operator	Number of wells	% reported SCVF
1	731	28.6%
2	453	24.5%
3	376	63.0%
4	310	23.2%
5	214	12.2%

4.2. Reported SCVF variability

As noted, we have seen a marked increase in reported SCVF since 2010, with varying degrees of reported SCVF between operators. To investigate we considered all horizontal gas wells drilled from 2010 to 2018 in BC and from within this set of 3302 wells, we selected those owned by the top 5 operators, in terms of number of wells. This subset consisted of 2084 wells and of these 30.0% had SCVF. Reported SCVF rates of individual operators are shown in Table 1.

There are no clear differences between the wells owned by these operators. All are horizontal and nearly all have been hydraulically fractured. Figs. 12 and 13 show the variations in TVD and MD. The distribution of wells depths is similar between operators with quite different SCVF rates. Operator 3 self-reports an SCVF frequency 33% higher than the average, while other operators report significantly less.

Although geological variations have been linked to SCVF in some studies e.g. Dusterhoft et al. (2002), this seems less likely here. Wells drilled since 2010 in British Columbia have been drilled in the same region of the Montney. Fig. 14 shows the location of the wells for each of the top 5 operators as discussed above. The grey symbols show all wells drilled in the Montney, with the coloured symbols being specific to these 5 operators. Aside from 56 wells belonging to operator 2 which are located in the Horn River basin (see inset of Fig. 14), all the other wells are located in the Montney. On inspecting the well locations of operator 3, the wells of other operators are nearby and separated only due to leasing/contracts. Fig. 15 focuses on operator 3, distinguishing SCVF (red) from non-SCVF (green), which shows adjacent red/green and suggests that geology is not the cause. Although operator 3 has significant numbers of leakers, there are in fact few with flow rates $Q > 10\ m^3$/day.

On closer inspection, we can find slight differences between comparable operators in terms of well depth and completion method (open hole vs cased). There may also be preferences in terms of cementing practices, cement blends and fracking, both concerning methodology and service contractors. However, this data is not publicly available. It is also possible that different operator's internal testing and reporting practices are more/less stringent than others.

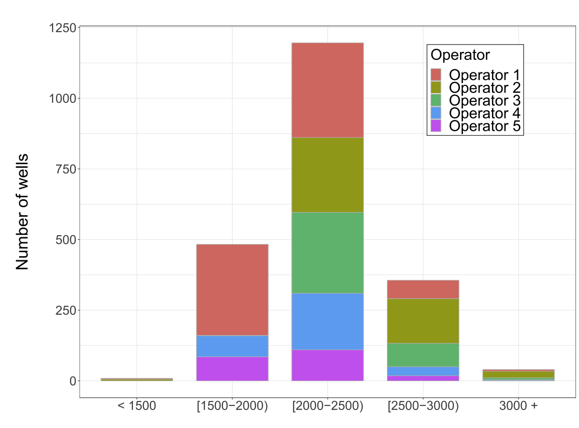

Fig. 12. True vertical depth for wells belonging to the top 5 operators.

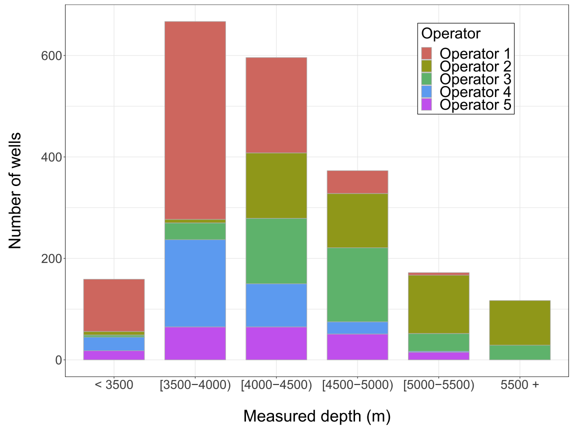

Fig. 13. Measured depth for wells belonging to the top 5 operators.

5. Methods of P&A

Drilling and production related activities taking place in BC are regulated by the BC Oil and Gas Activity Operations Manual (BCOGC, 2019b). Sections 8 and 9 of the manual set the requirements for drilling and abandonment activities. As per the requirements, permit holders must plug wells in such a way that ensures hydraulic isolation between porous zones, prevents leaking from the well, prevents excessive pressure build-up, and ensures the long-term integrity of the well is maintained. Gas Migration testing is conducted only if there is visible evidence (e.g. vegetation stress) of such a problem (BCOGC, 2019a). SCVF tests must be conducted before abandonment (BCOGC, 2019b).

Directive 20 (AER, 2018) is the primary document prescribing procedures for P&A activities in Western Canada. The directive was developed by the Alberta Energy Regulator (AER) but also adopted by BCOGC. This legal document describes approved methods of abandonment for different situations. In BC the wells are primarily gas (no oil sands) and so this is where we focus attention. P&A can be thought of as a sequence of zonal abandonment operations, starting downhole and working back up to the surface. Approved methods depend on several factors such as the completion type (liner, casing and or open-hole), recovery method (thermal vs non-thermal), reservoir fluids, and the well type.

The regulatory requirements allow some flexibility in methods used. Different operators favour slightly different abandonment practices and the service industry has evolved accordingly. Some guidance is also given by industry recommended practice documents produced by the drilling and completions committee of Energy Safety Canada, which coordinates with industry professional organizations, e.g. ESC (2017) which deals with cementing and abandonment.

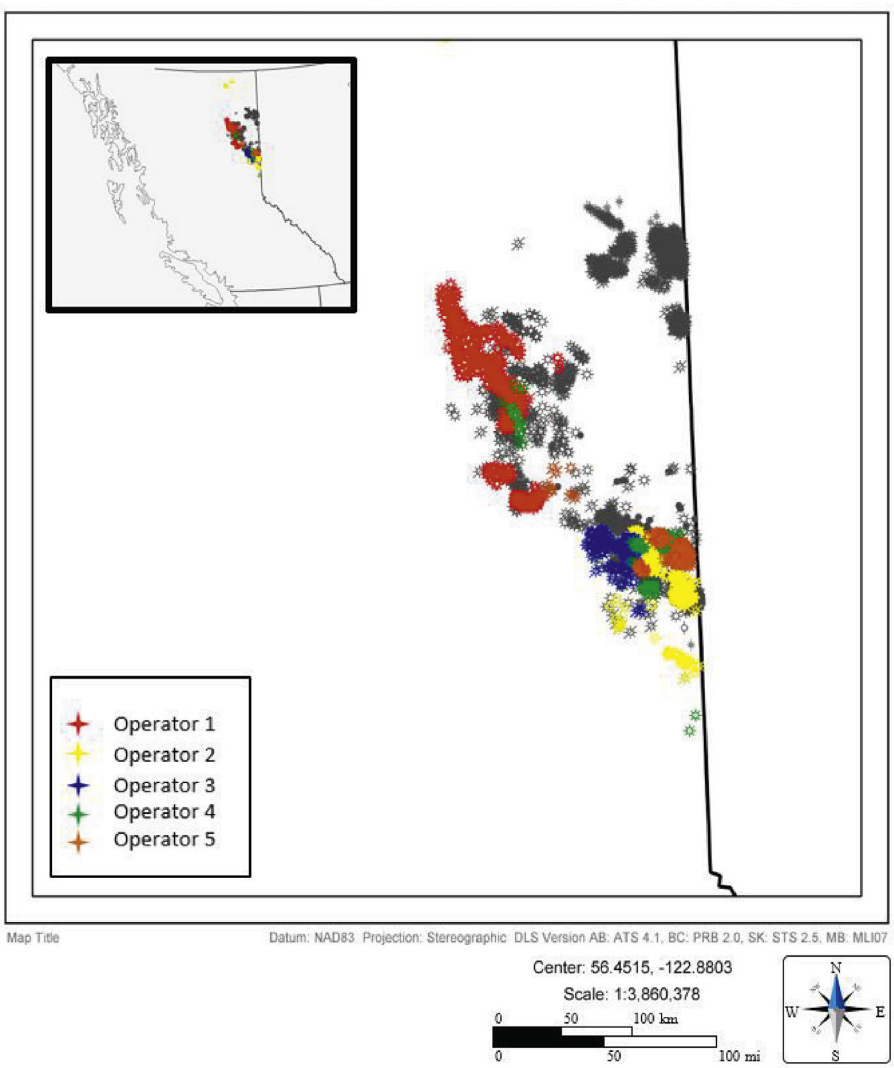

Fig. 14. Location of wells belonging to the top 5 operators in BC.

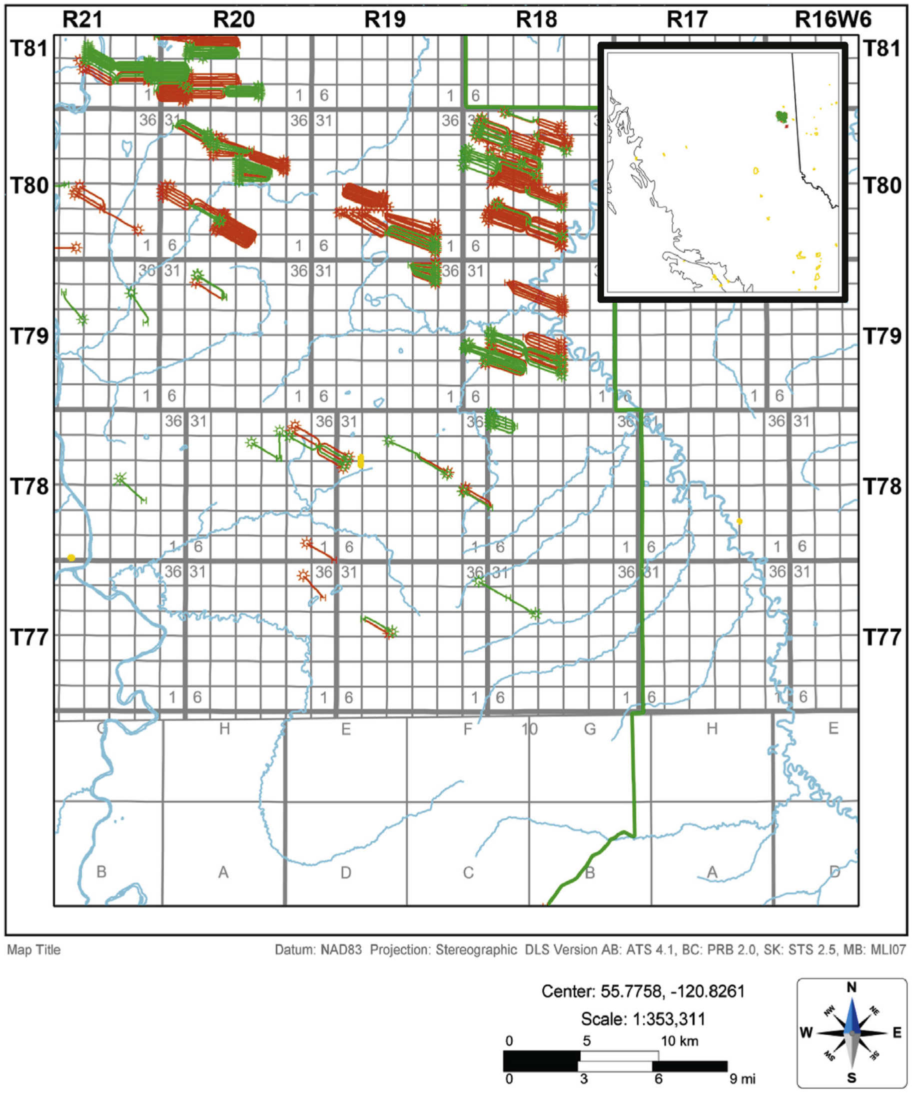

Fig. 15. Location of wells belonging to operator 3. Green symbol: no reported SCVF, red symbol: reported SCVF. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

5.1. Approved methods of zonal abandonment

One decisive factor affecting the abandonment plan is whether the well is cased or open-hole. A good number of open-hole abandonments are dry holes, i.e. wells that do not find a commercially viable hydrocarbon zone. Abandonment of an open-hole well requires covering or isolating all porous formations (using cement plugs only) and covering non-saline ground water zones.

Here we focus on abandonment of cased-hole wells that have been producing. Cased-hole wells may also include a single-zone open-hole production completion. P&A for cased-hole wells depends on whether the well was completed (i.e. perforated), and if the well was completed in a level-A interval; see AER (2018) for definition. Abandoning wells that were cased but never completed requires a 10 min pressure testing of the casing at 7 MPa. If no leak is detected, then there is no need to run any plugs and the casing can be cut and capped (vented cap welded to the casing) below the surface.

For cased wells with completion, each completed zone must be abandoned separately (AER, 2018). Fig. 16 illustrates the 4 approved plugging methods for vertical wells (non-level A interval) (AER, 2018; BCOGC, 2019b). These 4 options are:

1. Permanent Bridge Plug (BP) capped with 8-vertical meters of class G cement (or 3 vertical meters of resin-based gypsum cement). The BP must be pressure tested (at 7 MPa) for 10 min prior to capping with cement.
2. Setting a cement plug across the completed interval or the single open-hole section. The plug must extend at least 15 vertical meters below the completion (or to the plug back depth whichever is shallower) and 15 vertical meters above. The top of the cement plug must be tagged and the plug must be pressure tested to 7 MPa for 10 min.
3. Setting a cement retainer and pressure testing it at 7 MPa for 10 min, then conducting cement squeeze through the retainer into the perforations and or single open-hole section. The retainer must be capped with 8 vertical meters of class G cement (or 3 vertical meters of resin-based gypsum cement).
4. Setting a plug in a permanent packer above the completion. The plug must be pressure tested to 7 MPa for 10 min and capped with 8 vertical meters of class G cement (or 3 m of resin-based gypsum cement).

In BC the resin-based cement options do not appear to be used. If the completed zone is characterized as level-A, the requirements are more stringent (i.e. plug lengths are doubled). Operators are also encouraged to apply squeeze pressure to force cement into perforations. Moreover,

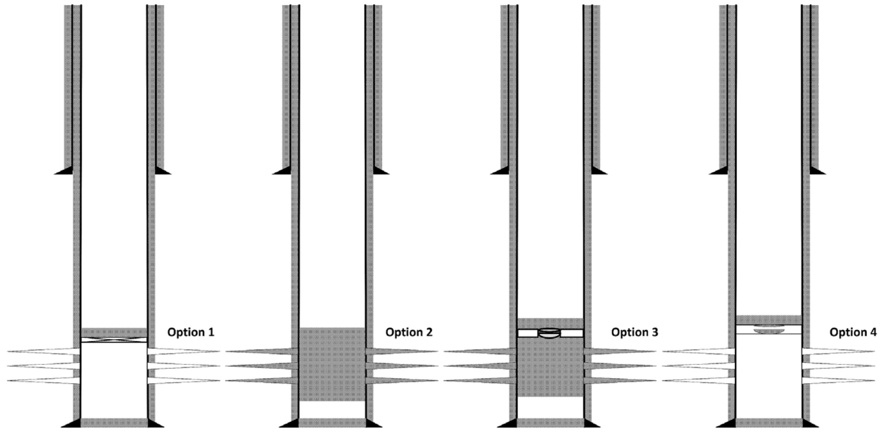

Fig. 16. Schematic representation of different options for abandoning a completed zone, according to AER (2018).

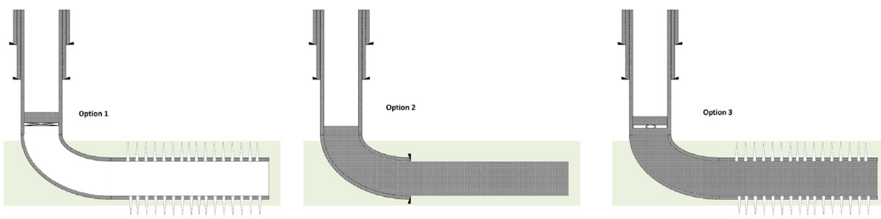

Fig. 17. Schematic representation of different options for abandoning a completed horizontal well according to AER (2018).

the use of a BP requires prior approval in this case.

For horizontal wells, the requirements for P&A are similar, with the exception of option 4 which is not allowed. The 3 approved abandonment methods for horizontal wells are schematically shown in Fig. 17. Note that the length of cement plugs are specified in terms of true vertical distance. Hence, the plug must always extend at least 8 vertical meters (for class G cement, with BP) above the completion regardless of the type of the well. For wells completed across multiple formations, each porous zone must be abandoned separately (no inter-zonal communication is allowed). Additional guidelines are available for wells completed using liners: not common in BC.

In the presence of SCVF/GM or the event of casing patches and failure, extra measures must be taken. ID 2003-1 (AER, 2003) prescribes approved methods for eliminating these problems. Remedial work includes identifying the source of the leak using an appropriate technique, then performing a cement squeeze to stop the leak. Operators are not allowed to pump cement or any other material down the annulus to stop the flow (AER, 2003). For abandoning a casing failure, casing patch or a previously cement squeezed intervals, only options 1 and 2 in Fig. 16 are allowed provided that it is in a non-level A interval.

The final stages of P&A consist of surface abandonment which requires cutting the casing 1–2 m below the surface and welding a vented cap to the casing, and lastly surface reclamation. Due to limitations in scope of this review, not all the P&A regulations in AER (2018) are discussed here.

6. Historical P&A data

Data on plugging procedures that have been used to abandon wells is publicly available.[2]. This data was used to study the P&A practices in BC. The analysis below does not differentiate level-A intervals from non-level A intervals.

According to BCOGC (2016b), as of December 2016, 24802 wells were drilled in the province, 30.7% of which were abandoned (=7614 wells). Around 6070 abandoned wells have documented data on the procedures used. Therefore, our analysis below is missing about 1600 wells. These may be missing for various reasons, e.g. changes in reporting requirements, changes in definition of what constitutes an abandoned well.

Requirements for open-hole abandonment were briefly mentioned in §5.1. The approved method of abandonment for these wells allows the use of long cement plugs to cover the porous formations. From the data we have, around 1950 of abandoned wells are found to have been abandoned open-hole. These wells almost exclusively have been abandoned using cement plugs. Fig. 18 shows the abandonment method used for open-hole wells on a yearly basis. The data shows most of the open-hole abandoned wells date back before 2005 which coincides with exploration periods in the province.

Taking out the open-hole wells from the data-set, leaves out about 4125 wells that are abandoned cased-hole. Among these, around 1000 wells appear to have been abandoned shortly after drilling (i.e. age <1 year). We remove these wells from the analysis because they are likely to be dry holes but also do not fit in the open-hole wells category. Combined with open hole, we see that historically about 50% of documented abandoned wells are likely to be dry holes. With the post-2005 shift to horizontal wells and pad drilling techniques, the percentage of dry holes has decreased significantly in the past decade, which may partly explain e.g. the drop-off in Fig. 18; see the earlier discussion in §3.1.

In terms of well trajectory, the majority of abandoned wells in BC are vertical (around 86%). In the analysis that follows all well types are considered. Fig. 19 shows the type of plugs used for (completed) cased-well abandonment. We have excluded around 6% of the reported abandoned wells from this set as having "no data", which comprises wells that either had incomplete plug data or no record of completion. According to the data reported in Fig. 19 and 28%–29% of wells are abandoned using cement plugs only while slightly more than 32% are abandoned using permanent BP capped with cement. Combination of plugs takes up more than 39% of the wells, e.g. a capped BP sealing the production zone and perhaps some remedial work higher up, with low pressure squeeze (option 3 of Fig. 16).

Fig. 20 shows evolution of the plugging method on a yearly basis. For a few years around 2000–2005, there seems to be an increase in

[2] https://www.bcogc.ca/online-services.

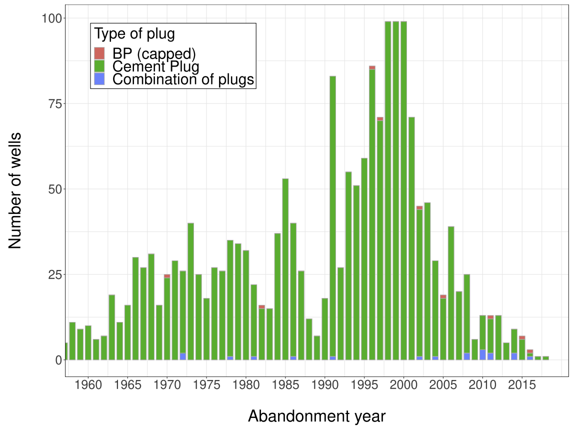

Fig. 18. Evolution of the plug type used in P&A of open-hole BC wells over time.

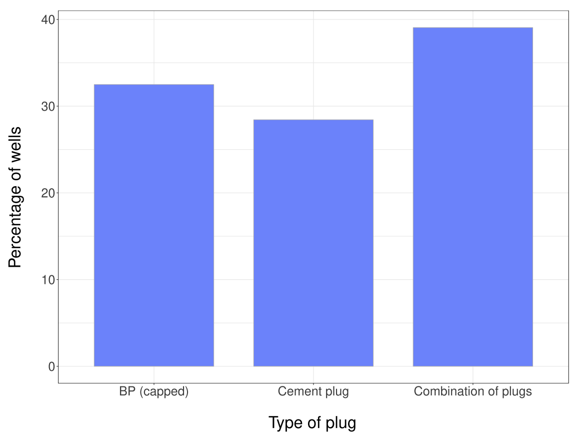

Fig. 19. Type of plugs used in abandoned completed cased-wells.

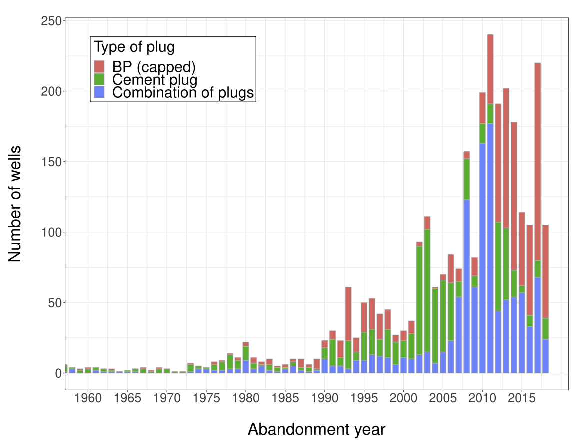

Fig. 20. Evolution of the type plug used in P&A of cased wells over time.

usage of cement plugs for abandonment. From 2005 to 2010 the method of choice appears to emerge as a combination of plugs and more recently a BP capped with cement. Fig. 20 also shows an increase in cased hole abandonments mimicking the growth in wells over the past 3 decades, whereas we have seen earlier that open-hole abandonments have reduced.

The distribution of the length of cement plugs for cased-hole wells is shown in Fig. 21. The length was calculated by subtracting the top and base of the plugs reported by the operator. The accuracy of the calculation is limited by the accuracy of the reported depths. According to

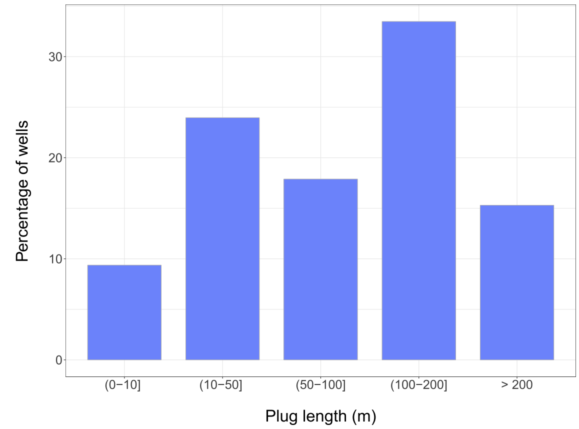

Fig. 21. Length of cement plugs set in abandoned cased wells.

the data, around 45% of the abandonment plugs have a length in excess of 100 m (328 ft). Note that cement plugs circulated in place for abandonment purposes do not have a prescribed length. As per regulation, for abandoning a completed zone (in one formation), a cement plug must cover the completed zone plus a minimum of 15 vertical meters margin from both the top and bottom.

The number of plugs (any plug) used per well is shown in Fig. 22 (cased-hole wells). Majority of wells (≈ 43%) are abandoned using only 1 plug. In this data, use of BP plus a regulation 8 m of cement has been considered as 1 plug, since the integrity of the cement cap is not individually tested. In 1-plug wells, the plug is likely to be protecting the producing formation. The danger in these wells is if this barrier fails over time, when there is no tested backup barrier. Around 20% of wells have 2 plugs. These wells likely have 2 completed intervals. Wells with many more than 2 plugs are more likely to have had integrity problems (including SCVF/GM) for which remedial cementing was performed.

Canadian P&A requirements are broadly similar to those in many onshore regions in North America. Many European regions have similar barrier recommendations for onshore as offshore (Oil and Gas UK, 2015). From an emissions perspective this is natural as environmental leakage does not respect international borders. It is therefore of interest to compare Canadian P&A designs with other international practices.

Norsok D10 standards advocate a minimum of 2 internal barrier elements for an abandonment (NORSOK, 2013). Internal barriers are the plugs placed inside the casing, as opposed to the annular cement sheath which is an external barrier. A BP capped with cement constitutes a two barrier system provided that it is capped with a minimum of 50 m (MD) of cement. On the other hand, a cement plug of at least 100 m MD length that is pressure tested to 1000 psi above the estimated

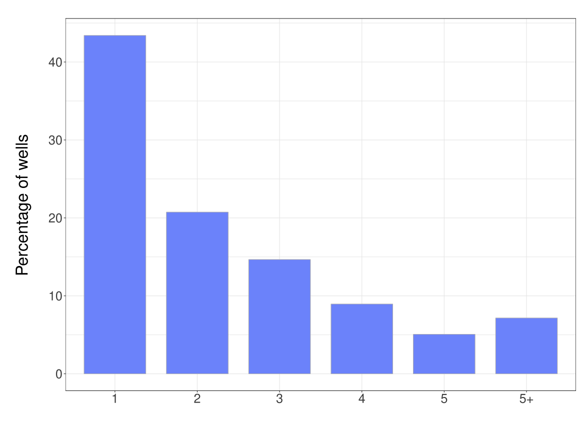

Fig. 22. Number of plugs used per well in abandoned wells.

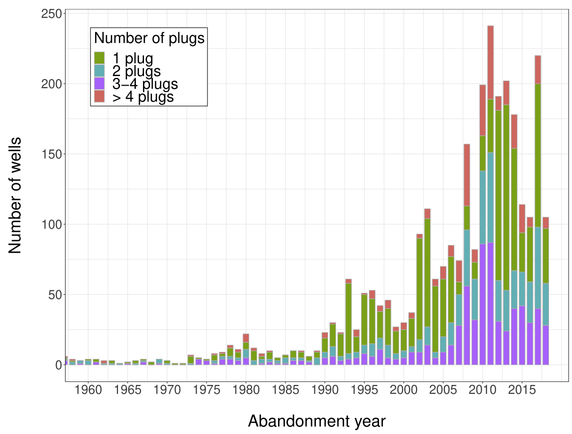

Fig. 23. Evolution of number of abandonment plugs used per well over time.

leak off pressure is considered acceptable as both primary and secondary well barrier. Comparing to the Norsok standards, almost all the wells with 1 plug in Fig. 22 constitute a one barrier element abandonment. For the wells with only 1 plug (1285 wells), 564 of them were abandoned with cement plugs and the rest using BP capped with cement. Wells abandoned using BP and the 8-vertical meters of cement fall into the one barrier system for two reasons. First, the elastomer sealing of the BP is not an acceptable barrier as per NORSOK (2013). Secondly, the required cement plug in Canada is 8 vertical meters of cement, and although 8 vertical meters can result in higher MD, in most wells the BP is set within the vertical section and hence the cement plug will not be 50 m in length. If we relax the testing requirements and only consider plug length as the deciding factor, then more than half of the wells with continuous cement plug would be categorized as a one barrier design. The same analysis applies to 2 plug wells, where the upper completed interval would be categorized as a one barrier design.

Finally, Fig. 23 shows the change in the number of plugs used in abandoning cased-wells on a yearly basis. The distribution of number of plugs over time shows no remarkable trends in the past 10–15 years. That is partly because the number of plugs used directly depends upon the number of completed production zones and then on repairing other problems such as SCVF/GM.

6.1. Testing requirements

Tests are performed before, during and after plugging a well. First, prior to starting downhole abandonment the top of the cement behind the casing must be determined. Available drilling records or theoretical calculations are acceptable means for confirming the cement top in the annulus. In case the cement top does not extend a minimum of 15 vertical meters above the uppermost porous interval the licensee must evaluate the cement by running logs.

Hydraulic isolation of porous zones must also be confirmed. However, the procedure for confirming hydraulic isolation is not clearly stated. In case hydraulic isolation is not confirmed, it must be taken care of by remedial cementing, i.e. squeeze cementing.

Testing for GM may be done using a soil vapour survey (BCOGC, 2019b), but is not mandatory unless there is evidence of GM, e.g. from observation at the ground outside the surface casing. In contrast, an SCVF test must be performed prior to commencing the abandonment process. This test is done primarily using the bubble test, as described earlier. The bubble test and its interpretation are debated within the industry. Undoubtedly a positive test indicates leakage, but accuracy of the rate, test procedure uniformity and sensitivity to atmospheric pressure variations have all been questioned. Various companies have developed more effective metering methods, but there is always a trade-off in cost vs simplicity.

Testing during and immediately after plugging depends on which abandonment method was used. If a BP or cement retainer is used, then the operator must pressure test them at 7 MPa for 10 min. The cement plug that is placed above a BP is subjected to no further test, i.e. since the BP holds the 7 MPa. For cement plugs that are circulated in place (e.g. option 2 listed earlier), these are also pressure tested at 7 MPa for 10 min. In addition the plug top is verified, typically by tagging the top of the plug using drillstring.

With regard to the pressure tests, these are one-way, i.e. from above. When a cement plug is subjected to pressure testing in a lab setting (see §8.4) seal failure is usually at the contact with the casing. Depending on the mechanics of this failure and the nature of contact above/below the plug, the failure could have a directional dependency. Neglecting this, the only untested plug would be that above a BP or retainer. If the 8 m cement cap is intended as an additional (secondary) barrier element this is problematic.

Lastly, a fluid level test is required for P&A of all open-hole wells prior to surface abandonment (AER, 2018). This test must be conducted at least 5 days after downhole abandonment. For the fluid level test the licensee must inspect the fluid level inside the casing and ensure it is static (no bubbles).

6.2. Reclamation and success of P&A

Restoring the wellsite is the last step in a P&A operation which involves significant restoration work (often costing a similar amount to the well plugging below). A certificate of restoration is issued by the regulator upon completing this step. As far as the regulation goes there is no requirement for going back and testing an abandoned well. However, the licensee of the well remains responsible for the well indefinitely.

Success of a P&A job as defined by AER (2018), is covering and protecting the non-saline ground water. BCOGC has a more inclusive definition of an abandonment job which includes ensuring hydraulic isolation of porous formation (i.e. no inter-zonal communication). However, BC regulations are based on AER (2018).

Given the long-term perspective of P&A there is some concern that a successful plug placement is solely judged by a positive pressure test for 10 min, and possible tagging of the top. The pressure test merely defines success over a short period of time. It is conducted long before hydration is completed. Certainly many causes of long term leakage (e.g. shrinkage, chemical corrosion) are not detectable at such an early time.

The use of a vented cap is designed to prevent excessive pressure build-up in the well, e.g. alleviating associated dangers. It makes a systematic study of the success of P&A harder to quantify in terms of leakage rate, as any gas by-passing the plugs within the well will diffuse through the near-surface soil covering the vent. Potentially these vents could be monitored for post abandonment leakage but this is not currently done.

BCOGC conducts surveys (Rygg, 2017; van Besouw, 2019) and audits wells occasionally. If they detect a well has not been abandoned up to the requirements, it would be the responsibility of the operator to fix the well. In recent years, fugitive emissions testing for approximately 100 abandoned wells has been undertaken by BCOGC. In their 2018 study, one abandoned well was found to be leaking due to SCVF (van Besouw, 2019). In British Columbia, nearly all oil and gas wells are located in the north eastern part of the province, where the population density is very low and access to all wells is difficult. Thus, information concerning wells post-abandonment is limited. BCOGC data shows about 300 of the >7000 abandoned wells in BC have been re-entered and re-abandoned, 23 of which underwent this process twice. This represents ≈4% of the abandoned wells in BC, and not all reasons for re-entry will be leakage related. By this measure we might consider most P&A operations to be successful.

7. Well preparation and placement

In this section we take a more mechanistic perspective and look at P &A, in terms of the well preparation and plug placement phases. Aside from regulatory requirements, best practice guidelines are also produced. In Canada, abandonment plugs are covered by section 25.10 of ESC (2017), which deals generally with cementing. Insofar as abandonment plugs are concerned, this document makes relatively few clear quantitative recommendations that might form the basis of a design methodology.

In the operation of setting abandonment plugs within casing, the key questions are as follows. (i) Is the inside of the casing suitably clean of residual fluid, so that the cement may bond to the steel? (ii) As the cement is pumped and the pipe pulled, what is the degree of mixing and does it leave sufficient length of uncontaminated cement? (iii) In the absence of a mechanical support below the plug, what is the expected motion of the fluids? Other design considerations relate to either the tools used or the cement properties and are covered in general texts such as Nelson and Guillot (2006).

7.1. Cleaning and displacement

The objective of placing of an abandonment plug is to seal the well below. Cement permeability is relatively low and unless the entire plug is compromised (e.g. via contamination), the most likely leakage paths are either at the cement-steel interface or through cracks/fissures that develop inside at a later stage. For the cement-steel interface the main requirement is that it be clean of residual fluids, so that the cement is able to wet the casing as it is placed, removing the in-situ fluid and remaining de-contaminated in any thin layers that form.

A large literature has developed concerning the fluid mechanics of cement placement during primary cementing, e.g. chapter 5 of Nelson and Guillot (2006) and the see the review in Frigaard et al. (2017). Although there are similarities, in P&A a variety of fluids may be in-situ. In a dry hole the fluid might still be a drilling fluid, but as indicated these are of less interest from the perspective of leakage potential. Otherwise the well may have been displaced to water at the end of production, but residual fluids at the wall could be hydrocarbons. The inside of the casing may be relatively clean and smooth, or may have scale buildup and other production deposits. Cleaning practices appear to vary with the operator. Aside from flushing with water, some may mechanically clean using either a gauge ring, rotating scraper or other device that removes loose debris. Unlike primary cementing in P&A there is less time pressure (driven by drilling costs and rig rates) and hence nominally there is time to allow the use of chemical solutions to presoak prior to washing. However, there appears to be little common use of chemical cleaners. Equally, there is little specific use of jetting for cleaning purposes. Neither regulations (AER, 2018) nor recommended practices (ESC, 2017) give much direction on cleaning.

If we consider the in-situ fluid to be a drilling fluid, then ESC (2017) recommends hole conditioning and pipe motion while circulating prior to setting the plug. While sensible, we must also recognise that the flow situation is different: the pipe is typically of small diameter relative to the casing ID (no narrow annulus), no centralisers are used and there is less risk of partially dehydrated/gelled mud at the walls, unless open-hole. Typical gap sizes and the eccentricity both increase the risk of residual mud remaining in the well, since the shear generated in the annulus is reduced, compared to that of primary cementing. This may be problematic in open-hole horizontal sections.

If this is a dry hole and the drilling rig is present, high flow rates may be achieved and potentially the enlarged annulus may still achieve turbulent flow. However, if it later in the well's lifecycle and a workover rig is to be used, pump capacities may be reduced. This makes it more likely that the flow of the fluids outside the placement tubing is in laminar flow, except near to the exit of the tubing. Thus, unlike primary cementing where significant wall shear stresses are generated and responsible for successful fluid removal, regardless of flow regime (Maleki and Frigaard, 2018), here the wall shear stresses will be significantly reduced. It is important to note that although buoyancy will remain and can be a significant aid to bulk fluid displacement, it is the wall shear stresses generated by the displacing fluid that are responsible for complete wall layer removal. The thickness of residual mud layer may be reduced by buoyancy but the condition to have no residual layer is independent of buoyancy; see Zare et al. (2017). Thus, drilling fluid removal in P&A can be problematic, which in turn may compromise the cement-casing interface.

On the other hand, if we are considering horizontal production wells as in BC, after the horizontal production zone has been plugged (Fig. 17), remaining plugs are placed in vertical (or less deviated) sections of casing. If we suppose that the casing has been effectively cleaned and displaced to water, e.g. plug placement as in Fig. 16, the main displacement flow consists of water being displaced upwards by cement slurry. Despite the low shear stresses, there is no yield stress in the displaced fluid and the significant buoyancy gradient present should make this effective. In contrast, if production hydrocarbons are not cleaned from the wall recent studies show that the displacement flow is very sensitive to wetting at low velocities (Hasnain and Alba, 2017; Hasnain et al., 2017).

7.2. Mixing during placement and POOH

Placement of cement plugs is an under-engineered field, in terms of techniques and tools. First we might consider the 4 generic plug configurations as in Fig. 16. Where 8 m or less of cement is placed, e.g. above a retainer or BP, this may be executed on wireline using a dumpbailer. Larger lengths are generally placed through tubing. The dumpbailer release is buoyancy driven, i.e. as the bottom of the dumpbailer is broken the density difference between fluids drives emptying of the tool. Estimates of the maximal emptying rate can be made, but using these to estimate mixing at the bottom of the plug is less relevant as the plug is supported mechanically.

In contrast, for plugs set through tubing the exit velocities, the jetting and mixing behaviour at the bottom of the plug would all be useful information for design purposes. As will be discussed below (§7.3), controlled mixing is one way to counter plug instability. Tubing can be drillpipe or coiled tubing, and the end can be completely open, or with a tailpipe/stinger/diverter. The latter have a range of geometries: blanked off or with array of nozzles, etc. There is also a range of flow rates used to place the slurry (and any preflushes). This is an obvious area where tool design could be finessed, but the process objectives have not been clarified. An ideal process scenario would be that the initial injection creates sufficient mixing to help stabilize the bottom of the plug, but that subsequent cement fills the well upwards. This is however not obviously the case, since the tubing is not centralised and more likely lies along one wall of the well. A stratified interface is very common in an exchange flow, i.e. heavy fluid in a layer on the lower side moving down, with light fluid moving upwards (Séon et al., 2005), even in vertical pipes (Beckett et al., 2011). Off-centre jetting would tend to promote this.

Jets themselves have been studied in depth for the past 80 years, e.g. List (1982), due to the wide range of atmospheric and industrial applications. However, within this broad literature P&A plug placement is to some extent a specialised application. If jetting sideways the impingement length is in the 1–10 cm range and the surface has curvature. The jetted fluid is generally non-Newtonian, but the in-situ fluid is often water. The viscosity and density differences are much more significant than in e.g. atmospheric jets. Similarly if jetting downwards, these distinctions are the same and typically the injected fluid (cement slurry) is density unstable. There are detailed studies on this type of flow configuration, when jetting downwards, but usually in density stable configurations and without confinement (Turner, 1966; Philippe et al., 2005; Hunt and Burridge, 2015; Burridge et al., 2015). With regard to non-Newtonian jets pumped into other fluids, there is little published. For example Maleki and Hormozi (2018) have considered a confined iso-dense viscoplastic axisymmetric jet in laminar flow quite recently.

With sufficient pumping velocity (for an off-bottom placement), we may expect that the bulk of the pumped slurry displaces upwards in the well. Both balanced plug and slight under-displacement are used, depending in service company. Withdrawal is usually after placement unless coiled tubing is used, which is less common. Industry recommended practices (ESC, 2017) are to pull slowly to avoid swabbing fluid motions, e.g. 5–10 m/min. The main idea is that viscosity will dampen small enough motions. It is also recommended to rotate the tubing as it is withdrawn. The tubing should be pulled above the top of cement, to minimize any jetting effect on the plug. The recommended practices in ESC (2017) appear sensible and there has been ongoing debate in the industrial literature regarding pulling out of hole (POOH). On the one hand, some advocate using a tailpipe/stinger (narrower diameter end-pipe) in order to reduce the volume of the pipe section within the plug. Sensible perhaps, but this also enhances the initial jetting and as Roye and Pickett (2014) show, it can slow the draining time associated with POOH so that the plug becomes unbalanced and unsteady motions ensue. Mixing/contamination within the plug can also come from mixing on the way down the pipe, where the flow is often turbulent and where it may not be feasible to used a rubberised separator plug. Some estimates of mixing lengths are made in Taghavi and Frigaard (2013) and see also Maleki and Frigaard (2016). A final issue can arise with short thickening times, that may delay any draining of the pipe, leading to a static imbalance after pulling (i.e. no “dry pull”) and consequent mixing higher up near the plug surface. Some service companies employ simulation tools in order to calculate balanced plug hydraulics e.g. as in Roye and Pickett (2014); Isgenderov et al. (2015), with reported success, but usage is not universal.

7.3. Buoyancy effects in off-bottom placement

As seen in Fig. 22 it is relatively common to have 2 or more plugs set in an abandonment in BC. The lowermost of these is associated with the production interval and subsequent plugs are above. These upper plugs are often set off-bottom, (e.g. with a low pressure squeeze as in option 3 of Fig. 16). In BC, since the wellbore fluid is typically water, this results in placement of cement over water, which is obviously mechanically unstable. Precise numbers are hard to determine, but it is common to find plugs placed above $100 - 300$ m of water. As with plug lengths, this is dependent on the distance between completed intervals and/or remediation depth.

Slumping of plugs placed off-bottom is a long-standing industry issue, also noted in ESC (2017) which recommends that “plug instability should be minimised”. The recommendations in ESC (2017) include the use of mechanical supports (e.g. bridge plug, retainer, umbrella-type, inflatable packer), or chemical means, i.e. a viscous pill (viscosified polymers, reactive pills, diesel gel, bentonite slurries, even a lower density cement mix). Mechanical devices are effective but add cost. Setting of viscous pills is also used on occasion in BC.

Plug instability has been an acknowledged industry issue for decades. In the 1990's it was widely expected that >2 plugs would need to be set off-bottom, before a successful job was achieved (Heathman et al., 1994). This study concerned plugs set while drilling, although the instability mechanisms are the same. The usual interpretation was that earlier plug failures mixed to form a viscous fluid of intermediate density, reducing the tendency to slump. Yard tests (Calvert and Smith, 1994) and a mix of lab experiments and theory (Frigaard, 1998; Frigaard and J.P., 1999; Crawshaw and Frigaard, 1999) resulted in improved guidelines for design of viscous pills, and further improvements came from the use of new mechanical devices. However, recent evidence suggests that lessons have either been forgotten or are not uniformly applied (Hudson et al., 2015).

In the context of Western Canada, it seems that a significant fraction of plugs will be placed off-bottom without any mechanical base, often on a water base. Many of these are set as part of a low rate squeeze (i.e. option 3 of Fig. 16). There is anecdotal evidence that these operations do result in an intact plug, as these are sometimes drilled out and pressure tested. These seems however to contradict physical intuition. If true, the physical reasons for success should be studied and understood.

Considering off-bottom plug stability from a purely fluid mechanics perspective, the instability can be prevented only 2 ways: (i) resist the destabilizing driving force of buoyancy; (ii) reduce the driving force of buoyancy. The complexity comes from wanting the plug to remain stationary after placement. Since fluids generate viscous stresses via velocity gradients, viscosity does not play a role in a static flow (Frigaard and J.P., 1999). Hence (i) implies generating resistive stresses that can be active when a fluid is static, i.e. a yield stress (or surface tension) effects. The yield stress needed to prevent plug slumping that is separated by a sharp interface from the fluid below, has been found and tested in Frigaard and J.P. (1999), and is given in terms of dimensionless ratios of yield stress to buoyancy stress. Some recent experimental studies in this area have been interesting (Maimouni et al., 2016; Varges et al., 2018). In particular Varges et al. (2018) show an interesting failure mode for when the underlying fluid has no yield stress and the fluids do not mix: the plug falls in the centre of the pipe. This axisymmetric/central failure mode was predicted earlier in Frigaard and Scherzer (2000) and highlights the importance of having a yield stress in the underlying fluid. Whether placement asymmetry and wellbore inclination would prevent the central mode from developing is unclear.

Under (ii) the main idea is to reduce the density difference, which is possible with a viscous pill of intermediate density. The idea is to split the destabilizing buoyancy stress between top and bottom interfaces of the viscous pill. An alternative that has not been explored is to purposefully mix a gradual change in density, e.g. via a combination of tailpipe/diverter design, maybe with graded mixing at surface and perhaps slow pulling while pumping. Unstably stratified density gradients are fairly common in nature (e.g. due to concentration or temperature gradients). The archetypical such flow is Rayleigh-Bénard, which remains stable for sufficiently low Rayleigh number. In this “graded” setup, diffusive processes (viscosity, conduction, diffusion) play a stabilizing role in dissipating fluctuations from the stable equilibrium (lowering the Rayleigh number).

Of course, we cannot expect a downhole pumped slurry to be perfectly stratified after placement, so some combination of (i) and (ii) is needed. Rayleigh-Bénard type stability limits are also affected (strongly enhanced) by the fluids having a yield stress (Zhang et al., 2006), and can be studied in scenarios where the underlying density gradients are not perpendicular to gravity (i.e. no static equilibrium for a Newtonian fluid); see Karimfazli et al. (2016); Karimfazli and Frigaard (2016). Here the yield stress also comes into play to stabilize the static flow. In parallel with the above fluid-based methods, it is advisable to control the transition (thickening) time chemically. This is a balance between risk of thickening in the pipe and having the slurry thicken as soon as possible after being placed, e.g. if one knew the timescales of the unstable motions one could design the transition time to thicken before too much of the plug is compromised.

8. Long term leakage and post-placement

We now turn to material and mechanistic aspects of longer term leakage. Regarding materials our main focus is on cement. The main point regarding cement is that it is a reactive material in which permeability, porosity and other mechanical aspects that affect well integrity develop over many different timescales. While convenient to pump a slurry that then sets solid, there are disadvantages of a reactive material. Recent development has been towards materials that overcome different disadvantages of cement, e.g. clays, shales, geo-polymers, …A broader discussion of other materials can be found in

Vrålstad et al. (2019a); Nelson and Guillot (2006).

Class G cement is the material used for the vast majority of P&A jobs in BC. In practice, different blends and additives are used preferentially by different companies, often with proprietary ingredients. We have not been able to assess the range of these. Since abandonment also requires cement casing integrity, the material used for the primary cementing and its placement techniques are also relevant. Primary cementing is more challenging in terms of placement and sealing, but has had a long history of materials based research to develop advanced blends, which may have different objectives to those used for P&A. For example, the cement sheath generally is thin but extends the length of the well, compared to plugs which are shorter but not placed in thin layers. Abandonment plugs are not structural components, they are generally not set in an over-pressured environment and permeability is the main material concern.

Lab tests show that class G cement which hydrates at downhole (P, T) conditions typically hardens and achieves a gas permeability $k \approx 0.01 - 0.1$ mD. Use of industry standard additives can reduce the permeability by 1–2 orders of magnitude, by design of cement particle size distribution, expanding cements and other techniques. Thus insofar as a sealing material goes, the permeability of a properly hydrated class G cement (with additives) is generally adequate, with $k < 0.001$ mD being a target value (Nelson and Guillot, 2006). However, permeability can be a sensitive property. With some of the plug setting procedures (§7) mixing and contamination may occur. The effect on hydration and permeability depends on the contaminant and concentration. For example, Le-Minous et al. (2017) considered different contamination concentrations with both sea water and water based mud (WBM). Only for WBM concentrations over 50% did the cement fail to harden, but permeability typically increased between 1 and 2 orders of magnitude. While contamination should be minimised, in many cases the bulk cement will still develop sufficiently low permeability to make other causes of leakage more important.

As we have discussed, from the regulatory perspective tests are only performed immediately after setting an abandonment plug. They consist of a pressure test and tagging the top of cement. Thereafter, it is hard to either measure or monitor anything downhole post-abandonment, e.g. time-dependent deformation of cement, change of downhole conditions, erosion of cement constituents by ionic compounds, other time-dependent natural phenomena. Some of these processes affect the cement sheath, which is an important barrier element and more exposed. Placement of the cemented annulus is more difficult, it must bond to formation and casing, and is directly exposed to formation fluids and stresses. However, some of the factors that affect long-term durability of cement are equally relevant to plugs and annuli.

From the mechanical point of view, since cement permeability is relatively low, integrity of cement sheath and plugs is most likely to fail by formation of cracks or by interface de-bonding. The following mechanisms have been identified as the main causes for formation of long term defects in a well cement:

1. Time-dependent deformation, e.g. shrinkage;
2. Degradation by chemical corrosion;
3. Variation of the downhole temperature/pressure.

Although not all these mechanisms are likely to affect a cement plug significantly over a short timescale, the combination of the above mechanisms accelerates the formation and propagation of damage. For instance, chemical degradation is accelerated at higher temperatures or in the presence of cracks. We now review each of the above mechanisms with the main focus on being able to eventually quantify these effects. In addition, the integrity of either plug or cement sheath can be compromised by hydraulic debonding, which we also consider below.

8.1. Time-dependent deformation and shrinkage

Time dependent deformation of the casing or other wellbore elements can result from tectonic forces, subsidence or other seismic activity. None of these are reviewed here. The first quantitative models for cement deformation were based on considering cement as a linear elastic material, such that deformation caused by thermal and external stresses can be obtained from linear stress-strain equations. The temperature distribution comes from the heat equation and suitable traction or strains are imposed at the boundaries, based on local formation conditions. Such models are essentially steady state mechanical balances with time dependency coming through evolution of either boundary conditions or other background fields. This type of steady state assumptions is reasonable beyond the pre-induction and induction periods of cement hydration.

However, considering cement as a homogeneous solid material is over-simplistic as a mechanical description, since fully set cement still encompasses pore fluids. This is modelled mechanically as a poroelastic material, based on Terzaghi's theory. The pore pressure in a saturated porous medium relieves some of the applied pressure on the material. In other words the effective stress in a fluid saturated porous medium is the difference between the total applied stress and pore pressure. The pore fluid is weakly compressible and pore pressure may vary over time, in particular during hydration. As a result of compressibility and chemical evolution, the solid skeleton balances an increasing portion of the applied stress.

In terms of modelling these transitions, the cement slurry is initially a fine colloidal suspension that changes on the micro-scale due to hydration reactions. As the solid phase increases in volume fraction, it attains a percolation threshold where particles (due to chemical bonds) begin to interact mechanically in a non-hydrodynamic way. From the early stage of cement hydration, conditions like low water to cement ratio (w/c), low RH, the heat released from the exothermic reactions, and high surrounding temperature lead to evaporation of water from the casing-cement interface (or from any residual layer there) and removal of pore water from the space between the particles. The initial chemical shrinkage of the cement, known as *plastic shrinkage*, occurring before cement begins to develop gel strength, is not thought to be very relevant to the mechanics of the set cement plug or sheath. During this stage, the volume reduction is not resisted: water bleeds upward and cement paste settles downward in a cement column, i.e. there is sufficient fluid motion to compensate locally for shrinkage.

As the solid fraction increases beyond percolation, chemico-mechanical contacts between grains develop, with the remaining liquid occupying the inter-granular space in the developing porous media. Fluid motion is progressively restricted. At this stage, capillary pressures, generated due to formation of menisci in the pores, continue to rise until they reach a critical “breakthrough” pressure, at which the maximum shrinkage occurs (Mindess et al., 2003). The pore pressure then starts to decrease. At this stage, if the cement is exposed, pressure reduction can drive fluid invasion from the formation (gas or liquid). With insufficient fluid flow the pressure can reach vapour pressure. Evaporation leads to generation of negative capillary pressures, disjoining pressures, and a variation of surface-free energy which causes the volume of the paste to contract. This phenomenon is known as *autogenous, drying shrinkage,* or *bulk shrinkage*. The volume reduction is now resisted by the gel strength of the solid cement network and by confinement effects, as cement is constrained (either in annulus or inside the casing).

This leads to the generation of tensile stresses: shrinkage cracking, micro-annulus formation and residual stresses. Any of these can diminish the integrity & bonding effectiveness of the cement and hence affects durability of both the cement sheath, the casing and the plug. Bulk shrinkage of the cement paste and its effects are believed to be mainly reversible, as they are linked to pore pressure. The main mechanism that contributes to variation of cement plug pore pressure is whether it has free access to additional water or not. If the cement plug is in contact with water, water diffuses into the cement structure and the pore pressure increases to avoid bulk shrinkage (Nelson and Guillot, 2006). This pressure build-up can occur on different time scales which depend on the permeability of the cement (Bois et al., 2012). In the annular cementing context, water may be extracted from residual mud layers (wet micro-annuli) or narrow side mud channels, resulting in a porous longitudinal conduit compromising integrity, or potentially extracted from the surrounding formation (which may help integrity). Various chemical additives and procedures are also used in cement blend design, specifically targeted at this stage, e.g. resisting gas invasion/migration, allowing expansion, decreasing permeability through cement particle size distribution.

The initial hydration stages up until onset of thickening comprise the operational window of a typical primary cementing or P&A job, i.e. hours, and at the time at which much of the well testing occurs, the cement is not fully cured: plastic shrinkage has occurred but bulk shrinkage is ongoing. The latter takes place over a period of days to months, over which key properties such as permeability continue to develop. In terms of modelling the above, there are significant difficulties in that the local features of reaction and shrinkage depend on operational features of placement and mud removal (settling, water availability, initial contamination), quite apart from complexity of the reactions themselves. Pragmatically, this means that the initial conditions for any later stage of modelling have a good degree of uncertainty.

The last stages of the chemical reactions of hydration are diffusion driven and can last over many years. Thermo-mechanical aging of the concrete/cement during hydration has been the focus of many studies aiming to make a quantitative prediction of the cement structure under thermal boundary conditions (Ulm and Coussy, 1998; Gawin et al., 2006a, b; Pesavento et al., 2008; Lecampion, 2013). The framework of these studies is based on the model developed by Coussy (2004) (known as Biot-Coussy theory) for a porous media saturated with pore water. In a nutshell, this model is based on the macroscopic thermodynamics of porous continua in which energy is dissipated via three physical processes: thermo- and fluid mechanical work and bulk dissipation. The hydration reactions contribute to the bulk dissipation via an overall property of the cement which is called “maturity” or “degree of hydration”. Porosity changes were initially missing in these models, e.g. Ulm and Coussy (1998). Later improvements by Gawin et al. (2006a, b); Pesavento et al. (2008) and Lecampion (2013) included the effects on the thermal stresses, both implicitly and explicitly. The explicit change was brought about by assuming a linear evolution of porosity with the hydration degree (Ulm, 2003; Brouwers, 2004). One of the earlier works modelling the thermo-mechanical aging of the cement is van Breugel (1997). The author developed computational models using the empirical relations obtained by earlier experiments to predict the quality of the cement (i.e. both morphology and structure). There are many other studies focuses at cement hydration and a wide range of mechanical modelling strategies of increasing complexity to be employed.

8.2. Degradation by chemical corrosion

Various studies have been made of chemical corrosion. In the abandonment context this mostly concerns integrity of the cement sheath, which although intact (or repaired) at abandonment may become compromised later. In general terms the depth of penetration of chemicals is governed primarily by diffusion in the interstitial pore solution, which has an effective diffusivity φD, where φ is the cement porosity and D the diffusion coefficient of the solute. Considering typical values, as a rough guide it takes around 10 years for corrosive material to penetrate 1 mm by diffusion mechanism solely.

Aside from diffusion chemical reaction may also occur. Cement interaction with carbon dioxide or brine leads to deposition and leaching of (sodium and calcium) salts within the body or on the exposed face of the cement. Perhaps, the most critical phenomenon resulting from $CaCO_3$ crystallisation is a solid volume increase; see Lesti et al. (2013). Sulfate attack (from downhole brines) may increase the solid volume by even larger amounts, also contributing to expansive forces. The main consequence of sulfate attack is significant softening of the cement and dissolution of the cement hydrates, C–S–H, and consequently significant reduction of the weight and strength of the cement (Mindess et al., 2003). Moisture content can develop pressure gradients due to significant build up of capillary pressures (of order MPa). These pressure gradients induce the flow of ions dissolved in the interstitial fluid which in turn can accelerate reactions, so that diffusive estimates may be an under-prediction; see Mindess et al. (2003). In a recent experimental study Newell and Carey (2012), the front propagation of CO_2, and CO_2 plus brine in Portland cement was compared using microscopy method. They observed a carbonation front at 5 mm penetration depth in the latter case while no front was observed at the same time with only CO_2. In the past 2 decades there has been a significant increase in research on CO_2-cement interaction, driven by interest in CO_2 storage, e.g. Um et al. (2011).

Many of the above chemical reactions result in solid volume increase at the pore-scale. Initially this may be beneficial in cases, reducing porosity and permeability, but generally drives expansion of the cement. Cement expansion may be partly beneficial in compensating for bulk shrinkage, but the expansion always generates stresses which can ultimately lead to cracking. We now see the critical long term issue of casing eccentricity, which is not effectively controlled and monitored in primary cementing. On the narrow side of the annulus (even in vertical wellbores), it is not uncommon to have 30% or more eccentricity so that cement thicknesses of 1 cm or less can result. Over a 50–100 year period significant depths of the sheath may become penetrated by reaction fronts: the thinner cement layers are more vulnerable to cracking. Thus, exposure to reactive chemicals in the surrounding formation carries the risk of long-term damage and then exposure of the steel casing to the same chemicals through cracks.

Cement plug exposure to chemical effects is much more limited, except in an open-hole section. In a cased section, exposure is coming primarily from below and may be shielded by barriers below (e.g. bridge plugs, lower plugs), whereas the annulus is exposed along its length. Expansion of the cement plug inside the casing produces a force on the casing that has been called the *Force of Crystallisation*. This may lead to expansion of the casing some closing of annular voids and cracks in the cement sheath. The stress generated by this force have been measured theoretically and experimentally in Wolterbeek et al. (2017).

Chemical degradation has been studied by exposing a cement sample to corrosive chemicals such as CO_2, H_2S and brine in idealized settings, (Lesti et al., 2013; Newell and Carey, 2012; Garnier et al., 2012; Lécolier et al., 2007, 2010; Wolterbeek and Raoof, 2018; Vrålstad et al., 2016). In these studies, the results were measured over a relatively small time scale. In addition, cement samples are often fully exposed to supersaturated corrosive gas or fluids, while in downhole conditions the exposed area is primarily limited to the pore structure of the cement and surrounding formation. Scaling effects, exposure questions and laboratory limitations suggest mathematical modelling would be useful. In particular, we are trying to extrapolate the results of tests that last days, months up to a year, to predict what happens over decades or centuries.

Chemical degradation and corrosion risk of steel reinforcement in concrete has extensively studied due to its importance in construction. For example, Mainguy and Coussy (2000) presents a model for Calcium leaching and chloride penetration (a diffusion-dissolution process in porous media) and predict the depth of chemical penetration with time. Thus, methods are available to adapt and utilize for casing corrosion.

8.3. Variation of the downhole temperature/pressure

A characteristic thermo-mechanical model is that of Thiercelin et al.

(1998) which is based on a linear-elastic thick hollow cylinder. The stresses induced in the cement due to variation of temperature and pressure are calculated using thermo-elasticity model and temperature field within the cement is found from solving the heat equation. More sophisticated models have been developed in house by some companies, e.g. Bosma et al. (1999); Ravi et al. (2002); Garnier et al. (2007, 2010); Fourmaintraux et al. (2005). Other authors have included the effect of time dependent mechanical properties of the cement into these models, with a similar outputs, e.g. Goodwin and Crook (1992); Philippacopoulos and Berndt (2002); Gray et al. (2009); Di Lullo and Rae (2000). The damage is characterized by means of tensile and Mohr-Coulomb criteria.

Mechanical and thermal loads and their influence on shear-bond and hydraulic-bond strength of the cement have been the focus of a number of studies e.g. Goodwin and Crook (1992); Parcevaux and Sault (1984); Stiles (2006); Shaughnessy and Helweg (2002); Boukhelifa et al. (2005). The shear bond strength between cement and formation, is evaluated by using a "push-out" test cell in which a vertical load is applied on a cylindrical cement bounded to container/formation until debonding occurs and the specimen moves downward in force direction. The shear bond strength is obtained by $\tau_c = \frac{P_{cr}}{2l}$, where P_{cr} is the pressure at which debonding occurs, l and τ_c are the length of specimen and shear bond strength respectively. In the abandonment context, any mechanical debonding is sufficient to compromise plug integrity. Thus, τ_c (for steel-cement) is indicative of a stress level to be avoided in any wellbore operation that affect the cement interfaces. This can also be used to rationalize a minimal pressure rating for a cement plug.

Of more relevance to leakage is the occurrence of hydraulic debonding (see below) and the formation of cracks, both of which lead to relatively large leakage pathways. Cracks may appear and create a connected pathways for gas leakage in response to thermal/pressure cycles. These are microstructural defects which cannot be identified using the push-out test. A visualization technique by using CT scanning has been recently developed and used to observe microstructural change of a cement specimen that has undergone thermal cycling (Albawi et al., 2014; De Andrade et al., 2014; Todorovic et al., 2016) and pressure cycling (De Andrade et al., 2016; Shadravan et al., 2015). In the wellbore context, on abandonment such cycles are most likely to come from operations on offset wells, e.g. thermally assisted recovery methods, or hydraulic fracturing. After abandonment and assuming limited proximity of producing wells, we may expect some pressure and temperature recovery in the reservoir, but significant geo-physically driven cycling is less likely. Methods such as Albawi et al. (2014); De Andrade et al. (2014); Todorovic et al. (2016); De Andrade et al. (2016); Shadravan et al. (2015) are however useful in giving us a versatile way of examining the distribution of leakage pathways in cement, as might be caused by these longer term effects.

8.4. Hydraulic debonding

The resistance of a cemented zone against the fluid migration is identified by its hydraulic-bond strength. In a method commonly used to measure this strength, a pressure is applied on a cement specimen subjected to air or nitrogen gas flow until leakage occurs. The minimum pressure at which gas perforates (the "breakthrough" pressure) is known as the hydraulic-bond strength of the cement (Parcevaux and Sault, 1984; Bearden et al., 1965; Liu et al., 2015). The equivalent permeability of cement plug can be also estimated by measuring the leakage rate. By equivalent permeability is meant that of the sample in the pressurized device, i.e. not necessarily the bulk cement. This depends critically on the hydraulic bond to the wall. For example, Nagelhout et al. (2010) consider 2 slurries: A - with a gas-blocking additive and no expander; B - with higher w/c ratio and an expander. Slurry A leaks under small differential pressures, through debonding at the wall. Slurry B did not leak for differential pressure gradients of up to 5.8 MPa/m, and even then the effective permeability of the plug was in the 0.01mD range. This type of testing has been conducted by different groups. Typically, leakage occurs at the cement-wall interface and the effective permeability of the plug drops once leakage starts. These devices are being developed in order to provide a reliable testing procedure for different slurry systems, hydrated at downhole conditions Nagelhout et al. (2010); van Eijden et al. (2017). Measured leak rates found to be a function of the radial scale of the cement plugs and the surface treatment. The leakage rates found in Opedal et al. (2018) indicate that exposing a cement plug to external water during curing has a significant improvement in the integrity of the cement, which is in agreement with our discussion of plastic and bulk shrinkage.

Leakage rates can be used to make a simple estimate of the micro-annulus thickness after hydraulic debonding. In non-lab settings one would need a microannulus to extend along the length of the plug. In a model presented in Bois et al. (2018), the hydraulic integrity of cement plugs is predicted and microannulus propagation is modelled in a similar way as a hydraulic fracture: propagation occurs if the fluid pressure in micro-annulus overcomes the cement stiffness. In Vrålstad et al. (2015); Skorpa and Vrålstad (2018), microstructural information obtained from CT scanning is combined with CFD to predict actual flow through the defects of a cement barrier. Not surprisingly the largest leakage is found either through micro-annuli or cracks, rather than through the cement sheath bulk. The authors fit their results to the Forchheimer equation and from this analysis they estimate bulk permeability for the 4 annuli cases considered. The estimated permeability is larger than that from other measurements and estimates (as is discussed and reviewed in Vrålstad et al. (2019a); Skorpa and Vrålstad (2018)), which is attributed to the irregular nature of the defects – in particular micro-annuli. This type of study can certainly provide the basis for a predictive model of well leakage, but some care is needed to deal with up-scaling from lab to well, and in particular the issue of connectivity of cracks/annuli along the well.

9. Summary and discussion

In this study we have reviewed data on wells and P&A practices in British Columbia. The main observations are as follows.

1. Overall in reviewing the data available to us, both in terms of numbers and in terms of specific abandonment schematics, the general impression is that the industry closely follows the regulatory requirements in P&A.
2. As with many parts of the world, BC is facing an unprecedented wave of well abandonments in the coming decades. This arises from a combination of old well stock, a ramping up of well numbers, from the mid 1990's until the recent downturn, and shorter lifetimes of newer wells.
3. Well trends since 2005 are dominated by monobore (unconventional) horizontal gas wells: pad drilled, with 2 casings and fracked in multiple stages. Dry hole abandonment rates are significantly reduced with current methods.
4. SCVF/GM is of relevance to P&A since it represents a significant increase in abandonment cost per well. From 2010 BCE changed the regulations on SCVF reporting, requiring self-reporting by operators. In wells drilled since 2010, 28.5% self-report SCVF, compared to 7.7% pre-2005. Analysis of wells released in 2005–2009 suggests approximately half of the increase in SCVF is due to self-reporting and the rest is due to other factors, the most obvious of which is the shift to horizontal wells as described above.
   (a) Analysis of wells released in 2005–2009 does not show any significant difference in leakage rates according to whether or not the wells were hydraulically fractured. We speculate that increased difficulty of horizontal cementing may be the cause.
   (b). Regarding the increase in SCVF due to self-reporting, we have observed significant variability in reporting between the largest 5 operators active in BC, with relatively little difference in well

location (except leasing/ontractual) or well type. This suggests some unwanted variability in either reporting or operational practices.

5. Approximately 43% of BC wells (that are not dry holes) are abandoned using one plug, or a bridge plug plus 8 m of cement cap. A further 20% have 2 plugs. Those with more plugs may have more completed intervals or correspond to wells for which remedial cementing work was needed.
6. There is considerable variation worldwide in regulatory aspects of P &A; see Van der Kuip et al. (2011), and even the underlying objectives of P&A. The abandonment designs employed in BC are broadly similar to those of other onshore North American jurisdictions, but many would not satisfy the more stringent requirements of e.g. offshore North Sea.
7. Given the increased recent SCVF rates, reduced dry-hole abandonment rates and shorter well lifespans, it is safe to assume that average P&A costs per well in BC will rise significantly in the future.
8. As with other jurisdictions, testing in BC is limited. Plug locations are typically checked via tagging and integrity via a one-way pressure test. There is also little systematic logging of wells (CBL or ultrasonic) to establish annular integrity, except to help determine/ fix SCVF issues.

While the above are observations specific to BC data, there are also a number of more general issues with regard to P&A. First, P&A is viewed as a cost item for most operators. Thus, although regulations are followed they are not typically exceeded. A significant part of long-term well integrity of an abandoned well comes from the integrity of existing casings. These however have been designed at the drilling stage and primarily to satisfy construction and production objectives. Primary cementing is also viewed as a cost item for drilling, typically performed in a constrained time window. Primary cementing defects are not felt immediately in construction, so there is no incentive for successful cementing, as measured long term. Until the industry manages well integrity issues collectively, from drilling onwards to P&A, allowing performance indicators and design objectives to be fed backwards to construction and production decisions, the incentives for good P&A will be lacking and will remain a cost burden enforced by regulatory means. In Western Canada this type of collective and long-term approach to improving P&A is increasingly adopted by regulators, industry and other stakeholders contributing to best practices, technology roadmaps and scientific study (NRC, 2019).

A missing piece technically is that evaluation and testing of implemented practice is too infrequent and not detailed enough to allow continuous improvement. For example, eccentricity of the annulus has been known as the most important cause of poor cement placement for 60 + years. However, regulations underlying centralization are nonexistent in most (all?) jurisdictions and best practice recommendations are minimalist. The consequence is there is little systematic recording of centralizer programs actually implemented and to our knowledge no methods of testing the actual placement positions and in-situ stand-off. Some indications come from logging but the frequency of running a cement bond log (CBL) or ultrasonic log on a cemented well is very low, except for high cost wells. Thus, significant eccentricity, which often leads to mud channels and micro-annuli in cement placement, persists as a long-term industry issue where the narrowest part of the cement sheath is the most vulnerable to both mechanical stresses and chemical attack. The information in a pressure test is minimal compared to that in a CBL. There have been a large number of field case studies over the past decade that compare logs with model/simulation (fluids placement or risk microannulus): sufficient to prove the utility of more detailed evaluation and modelling. However, these remain "nice" case studies, instead of an integral part of systematic evaluation and improvement. In our view there needs to be significant emphasis on detailed post-job evaluation of both primary and plug cementing.

With regard to regulatory aspects of P&A, in BC 3 missing aspects are as follows.

1. There are no specified requirements for cleaning the inside of the casing to ensure a good bond.
2. In pressure testing any cement plug, there needs to be the possibility of leakage beyond the plug. Thus for example, the 8 m plug placed over a BP (already tested to 7 MPa) is untested as the BP already supports the pressure. A plug placed in the casing, above lower plugs, is also untested unless e.g. there is a completed interval that is being isolated.
3. There is no specified requirement to use a mechanical (or fluid) support when setting a plug off-bottom, which occurs in particular when performing a low rate squeeze (e.g. option 3 of Fig. 16). Thus, there is no control specified to counter buoyancy driven mixing and destabilization.

As we have discussed, P&A regulations in BC fall on a spectrum of regulatory possibilities. As we look forwards to "post-industry" well integrity in Western Canada and globally (within 50 years?), we should remain open to both critical comparison with other jurisdictions and consideration of alternatives.

We have also reviewed mechanical studies related to well integrity. This is a challenging area to study due to physicochemical complexity and to the wide range of length and timescales. This difficulty is compounded by the problems of decoupling/isolating smaller digestible parts of the entire process, that may be studied in depth either via model or laboratory experiment, whereas the many parts are interconnected. Certainly there is much scope for both academic and industrial research. Practically, when we view the large disparity in regulations worldwide we are led to questions like: "Why is 8 m of cement above a bridge plug sufficient?", "Are 2 barriers needed?", etc. These are questions that research should be able to address in increasing detail moving forward.

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Nomenclature

P&A	Plug and Abandonment
BC	British Columbia
SCVF	Surface casing vent flow
GM	Gas migration
HPHT	High pressure high temperature
BP	Bridge plug
API	American petroleum institute
BCOGC	British Columbia oil & gas commission
MD	Measured depth
TVD	True vertical depth
LMR	Liability management rating
AER	Alberta energy regulator
POOH	Pull out of hole
φ	Porosity
D	Diffusion coefficient
τ_c	Shear bond strength
P_{cr}	Pressure at which debonding occurs
l	Length

CT	Computer tomography
CFD	Computational fluid dynamics

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